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NATURAL GAS MARKET

HEARINGS

BEFORE THE

SUBCOMMITTEE ON
ENERGY REGULATION AND CONSERVATION

OF THE

COMMITTEE ON
ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

NINETY-NINTH CONGRESS

FIRST SESSION

ON THE

CURRENT STATE OF AND THE FACTORS AFFECTING THE NATURAL GAS MARKET

JUNE 18 AND JULY 11, 1985

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NATURAL GAS MARKET

TUESDAY, JUNE 18, 1985

U.S. SENATE,
SUBCOMMITTEE ON ENERGY
REGULATION AND CONSERVATION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The subcommittee met, pursuant to notice, at 9:35 a.m., in room SD-366, Dirksen Office Building, Hon. Don Nickles presiding.

Present: Senators Nickles, Warner, Evans, Ford, Bradley, and Bingaman.

Also present: Howard Useem, professional staff member; and Elizabeth Moler, counsel for the minority.

OPENING STATEMENT OF HON. DON NICKLES, A U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator NICKLES. Good morning. Good morning, Senator Warner.

Senator WARNER. Good morning.

Senator NICKLES. Today the Subcommittee on Energy Regulation and Conservation is holding an oversight hearing to review the current state and factors affecting the natural gas market. This is the first of 2 days of hearings.

At today's hearing the subcommittee will receive testimony from the administration. On the second day, the subcommittee will receive testimony from industry and other witnesses. Originally we had planned on having a 1-day hearing. However, several witnesses requested a delay in their appearance due to the Federal Energy Regulatory Commission's May 30 issuance of a notice of proposed rulemaking on pipeline regulation. The subcommittee has accommodated their witnesses. The date for the second hearing will be set in the near future.

During the 98th Congress, the Committee on Energy and Natural Resources held hearings on the state of the natural gas market and reported to the Senate a bill to deal with the problems that were identified.

Some of the problems addressed by the legislation were already occurring in the marketplace, and others were expected to be triggered by the partial decontrol of natural gas on January 1 of this year. It is now 6 months after natural gas was partially decontrolled.

Are the problems that were previously occurring in the marketplace still occurring? Has the partial decontrol of natural gas on January 1, 1985, resulted in the problems that many were predicting? For example, has there been a price flyup?

In the light of the current state of the market and FERC's proposed changes in pipeline regulations, why shouldn't the remaining price-regulated natural gas be deregulated? These and other questions will be discussed in detail in both days of this hearing.

I might mention, too, that when I was in Oklahoma with the President he indicated his continuing support for the decontrol of all natural gas. On June 13, I introduced Senate bill 1302 which would complete the task of deregulation. It also contains provisions to repeal artificial fuel use limitations of the Powerplant and Industrial Fuel Use Act, and incremental pricing provisions of the Natural Gas Policy Act.

The two witnesses today are Hon. Raymond O'Connor, Chairman of the Federal Energy Regulatory Commission, and Hon. Danny Boggs, Deputy Secretary of the Department of Energy.

I wish to welcome both of you to this committee, and I want to commend both of you for the work that you're doing. I think we've got some real challenges.

Mr. O'Connor, especially I look forward to your statement to, hopefully, help me and other members of this committee, and also industry officials and interested persons to better analyze and interpret the proposed rulemaking which you've submitted.

Senator Warner, we welcome you to this hearing, as well. Do you have any opening comments?

STATEMENT OF HON. JOHN W. WARNER, A U.S. SENATOR FROM THE STATE OF VIRGINIA

Senator WARNER. Thank you, Mr. Chairman.

I wish to thank Mr. Boggs in connection with another matter in a previous hearing of this committee for facilitating the appearances of witnesses from the Department of Energy.

Thank you.

Senator NICKLES. Mr. O'Connor, do you care to be first?

STATEMENT OF HON. RAYMOND J. O'CONNOR, CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION, ACCOMPANIED BY KENNETH WILLIAMS, DIRECTOR, OFFICE OF PIPELINE AND PRODUCER REGULATION, FEDERAL ENERGY REGULATORY COMMISSION

Mr. O'CONNOR. Good morning, Mr. Chairman and members of the committee. I have with me today Mr. Kenneth Williams, who is the Director of our Office of Pipeline and Producer Regulation, and also other senior staff members who may assist in answering any questions you may have.

I am pleased to appear before you and the members of the subcommittee to discuss the Commission's notice of proposed rulemaking regarding changes in our regulations governing transportation of natural gas by pipelines. I will also be pleased to discuss other developments at the Commission concerning the sale or transportation of gas in interstate commerce.

To the extent these matters are currently pending before the Commission or the courts, and in order to assure that the rights of parties are not prejudiced, I must, of course, refrain from commenting on the merits of these matters. The views I express are my own and do not necessarily represent the views of the Commission or any other Commissioner.

As a preliminary matter, the Commission is committed to being fully responsive to you and other leaders in Congress in your oversight of the authority that has been delegated to us under the Natural Gas Act and the Natural Gas Policy Act.

In light of partial wellhead price decontrol of natural gas after January 1, the Commission's goal has been simple: To secure for American consumers the full benefits of competition in natural gas markets consistent with our legal responsibilities under the Natural Gas Act and the NGPA. The Commission has faced difficult challenges in connection with natural gas wellhead deregulation as we have moved to respond to the growth of competition in the gas industry.

In a nutshell, the Commission's concern is that price signals resulting from this competition be transmitted accurately between the burner-tip, the city-gate, and the wellhead in order to assure that rates and services established under the Natural Gas Act are just and reasonable and in the public interest.

I am proud that the entire Commission and its staff have been united over the last year as we have begun to meet these goals on a timely and predictable basis.

The summary of the proposed rulemaking: On March 29, the Commission concluded the public proceedings in its three-phase notice of inquiry which we commenced in December 1984. The Commission has received over 200 detailed comments from entities representing all facets of the natural gas industry, consumers, State regulators, businesses, and public agencies. Those comments addressed a wide range of topics and provided a wealth of information and insight to guide the Commission.

During the past 5 months, we have also begun to observe the actual behavior of the industry, including field markets, burner-tip markets, and capital markets, following the partial removal of wellhead price controls on January 1, 1985, in accordance with the congressionally mandated schedule contained in the NGPA.

On May 30 the Commission issued the notice of proposed rulemaking containing four major parts.

Part A would provide for blanket transportation authority, but would require that such transportation be offered on a nondiscriminatory basis. It would permit local distribution companies to adjust from firm sales entitlements to firm transportation with no more than 25 percent of the firm sales' entitlement to be adjusted in any one year unless otherwise permitted by the pipeline suppliers. Transportation rates would be volumetric and based upon representative levels of throughput. They would be flexible downward at the pipeline's risk.

Part B: Those pipelines willing to provide nondiscriminatory transportation would be able to buy out problem contracts with high take-or-pay obligations and indefinite price escalator clauses. There would be a rebuttable presumption of prudence if the buyouts meet certain criteria.

Part C: Pipelines would have available to them optional certificates which would permit construction of facilities and the offering of new services provided the pipelines are willing to be at risk for the failure of the project or for less utilization than anticipated. In no event could the costs be shifted to other services.

And finally, Part D would require purchased gas to be separated between old flowing gas and new gas which would be billed under separate blocks. This approach would assure that existing customers have available their proportionate share of old gas, while at the same time are aware of the cost of additional supplies. This would enable pipelines to compete on a more equal basis rather than have competition influenced by the amount of old gas that is available to them.

The Commission has emphasized that this package is intended to be a comprehensive, integrated approach to the problems that plague the natural gas industry. We believe it would be a mistake to deal with these problems in a piecemeal fashion. There is no one problem to the industry. There are many interrelated problems.

Pipelines have resisted nondiscriminatory transportation because they have take-or-pay problems and there are competitive distortions created by the different mixes of the old-gas cushion owned by some pipelines. Because there are disincentives to transportation, producers who want to sell gas and marginal customers who want to buy gas cannot connect. Because pricing signals are distorted by various policies, consumers are encouraged to make choices that result in an inefficient allocation of scarce resources and distorted investment decisions.

The proposed regulations are intended for the most part to supplement existing Commission regulations and provide additional options to interstate pipelines that seek increased flexibility in offering those services that their customers wish to purchase.

The proposed regulations permit pipelines to enjoy greater flexibility and the opportunity for increased returns as long as the pipeline is willing to assume the economic risks of under-recovery of costs. With one notable exception, there is no requirement in this proposal that would be imposed involuntarily on any pipeline. Rather, a pipeline that so desires would remain free to offer natural gas sales and storage services in which the transportation component of the service is part of a package or bundle of services.

The various access and rate conditions would only apply if the pipeline chose after the effective date of the proposed rules to hold itself out as a transporter of gas for others under the simplified program. The exception is the requirement that all pipelines separate out for billing purposes their supplies of old gas.

Under this billing mechanism, the subsidy associated with the old price-controlled gas would be effectively allocated to the historical customers. This requirement is intended to help level the playing field by requiring all pipelines to compete for new markets on the basis of their current cost of new gas supplies unaffected by their relative shares of old price-controlled supplies.

In conclusion, in addition to the proposed rulemaking, the Commission yesterday afternoon issued a final rule extending through October 31, 1985, the eligibility for low priority natural gas customers to have gas shipped to them under the blanket certificate program, or the Order 234-B Program.

In order to effectuate this extension, the Commission yesterday afternoon filed a petition with the court of appeals, a petition for a stay of the mandate of the court which vacated Order 234-B in the recent *Maryland People's Counsel* case.

That concludes my oral statement, Mr. Chairman. I would be pleased to answer any questions.

[The prepared statement of Mr. O'Connor follows:]

STATEMENT OF
RAYMOND J. O'CONNOR
CHAIRMAN, FEDERAL ENERGY REGULATORY COMMISSION
BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

June 18, 1985

MR. CHAIRMAN AND MEMBERS OF THE SUBCOMMITTEE:

I am pleased to appear before you and the others members of the Subcommittee to discuss the Federal Energy Regulatory Commission's (Commission) Notice of Proposed Rulemaking regarding changes in our regulations governing transportation of natural gas by pipelines. I also will be pleased to discuss with you the status of other regulatory developments relating to the Commission's jurisdiction over the sale or transportation of natural gas in interstate commerce.

To the extent these matters are currently pending before the Commission or the courts, and in order to assure that the rights of parties are not prejudiced, I must. of course, refrain from commenting on the merits of these matters. The views I express are my own, and do not necessarily represent the views of the Commission or any other Commissioner.

As a preliminary matter, the Commission is committed to being fully responsive to you and other leaders in Congress in your oversight of the authority Congress has delegated to us under the Natural Gas Act (NGA) and the Natural Gas Policy Act (NGPA). I have been pleased to have your advice and counsel on the record on these and other issues.

In light of partial wellhead decontrol of natural gas after January 1, 1985, the Commission's goal has been simple: To secure for American consumers the full benefits of competition in natural gas markets consistent with our legal responsibilities under the NGA and the NGPA.

The Commission has faced some difficult challenges in connection with natural gas wellhead deregulation, as we have moved to respond to the growth of competition in the gas industry.

In a nutshell, the Commission's concern is that price signals resulting from this competition be transmitted accurately between burner-tip, city-gate, and wellhead in order to assure that rates and services established under the NGA are just and reasonable and in the public interest.

I am proud that the entire Commission and its staff have been united over the last year as we have begun to meet these goals on a timely and predictable basis. The Notice of Proposed Rulemaking is intended to provide regulatory predictability and administrative certainty to the industry and consumers in their own efforts to respond to the new competitive realities in natural gas markets.

I will be pleased to discuss the Notice of Proposed Rulemaking, and then summarize the current status of a number of regulatory developments which have led up to the proposed rule.

SUMMARY OF PROPOSED RULEMAKING

On March 29, 1985, Commission concluded the public proceedings in Phases I, II, and III of our Notice of Inquiry in Docket No. RM85-1-000 (NOI), commenced in December of 1984. In that proceeding, the Commission received over 200 detailed comments from entities representing all facets of the natural gas industry, consumers, state regulators, businesses, and public agencies. Those comments addressed a wide range of topics and provided a wealth of information and insight to guide the Commission.

During the past five months, we have also begun to observe the actual behavior of the industry -- including field markets, burner-tip markets and capital markets -- following the partial removal of wellhead price controls on January 1, 1985, in accordance with the Congressionally-mandated schedule contained in the NGPA.

We have also begun to receive the guidance of reviewing courts of appeal of some of the initiatives set in motion by the Commission over the last year and a half in anticipation of partial wellhead decontrol.

In addition, we have been informed by the comments of elected representatives in their oversight of the Commission's exercise of its delegated authority and by executive branch policymakers pursuant to the NGPA.

The NOI comments, judicial decisions, and comments of both the legislative and executive branches of the Federal Government -- and our own experience -- have led us to the conclusion that the present regulatory framework for the natural gas transmission industry may not be as well adapted as it could be to the economic realities of the industry as they exist today and are likely to evolve in coming years. As pointed out by the commenters, the partial removal of wellhead price controls mandated by the NGPA has been responsible in large part for economic forces that have fundamentally changed the behavior of the various segments of the natural gas industry. This evolution in the industry appears to have been impeded to some degree by a regulatory framework which, while well adapted to the earlier period, has not been sufficiently adjusted to promote adequately the public interest in the newer, evolving competitive environment.

For these reasons, as detailed more fully below, the Commission is proposing a series of changes in our existing rules. The Notice of Proposed Rulemaking was unanimously issued by the Commission by a 5-0 vote on May 30, 1985, and provides for comments by the public by July 15, 1985, and a public hearing to be held on July 30, 1985.

Our overall goal is to make such adjustments in our regulation of interstate transportation of natural gas as are required to ensure that consumers are provided natural gas at the lowest, reasonable rates consistent with reliable, long-term service. If we are successful in this goal, we will also be fostering a more efficient allocation of scarce resources among the energy production, transmission and consumption segments of the economy. That, in turn, will permit natural gas (and other energy sources, to the extent that natural gas prices affect other energy prices) to play the appropriate roles in producing goods and services which their respective comparative advantages and real economic costs permit.

In light of the comments and our obligations under the NGA, the NGPA and the Department of Energy Organization Act, it appears appropriate to propose changes to our regulations to address these points. Accordingly, the Commission has proposed to modify its rules in the following four specific areas, pursuant to sections 4, 5, 7 and 16 of the NGA, sections 311 and 501 of the NGPA, and sections 402 and 403 of the Department of Energy Organization Act.

Part A -- Transportation

- A simplified transportation program is proposed, including blanket certificates under section 7 of the NGA and transportation under section 311 of the NGPA, conditioned to require nondiscriminatory access to such transportation.
- A conditional opportunity would be created for customers of pipelines to modify their existing service agreements in order to reduce their contract demands for firm sales

service. This customer option would only be available if the pipeline held itself out as a transporter of gas for others. Pre-granted abandonment would be available to the pipeline to the extent of any customer's reduction in its purchase entitlement. This would enable such customers to choose more freely among a portfolio of service options offered by pipelines. This would entail an adjustment in the pipeline's sales obligation under its existing service agreement and certificate, and revision of any demand charges, minimum bills, etc., that may be required under the firm sales tariff for the sales service being adjusted.

- Traditional sales and transportation options would remain available to pipelines and their customers under the Commission's existing certificate authority.

Part B -- Take-or-Pay Relief.

- During a limited transition period, solely at the option of pipelines and their producer-suppliers, a rebuttable presumption of prudence would be established for certain limited and circumscribed payments made by pipelines to extinguish all future minimum payment or purchase obligations in certain contracts.
- This presumption would be available only to pipelines willing to offer nondiscriminatory access to transportation service; this in turn gives rise to an option for firm sales customers to reduce their contract demands.

Part C -- Optional Expedited Certificates.

- Optional expedited certification procedures under section 7 of the NGA for new or expanded services, facilities and operations would be established and would be made available by choice to pipelines willing to assume the risk of these ventures by agreeing to specified conditions (including volumetric rates) governing the proposed services.
- Appropriate abandonment may generally be pre-granted to the pipeline to be effective at the expiration of the underlying contracts. In those instances where the customer has an alternate provider of service, the pipeline would be able to discontinue service at the expiration of the applicable private contract.
- Because pipelines would knowingly assume the risk of their ventures, competing certificates would be granted.
- Traditional certification procedures would remain available to pipelines seeking to impose some of the risk of their venture on other parties, in order to ensure that the risk imposed on others is required by the public convenience and necessity.
- Where customers have no alternate provider of service and are willing to pay the just and reasonable rate for continued service, abandonment would require Commission approval.

- The initial rates for optional expedited certificates authorizing such unbundled services would be volumetric rates. The costs of such services could not be shifted to other services.

Part D -- Billing Mechanism for Old Gas Supplies.

- A three-part gas rate would be required for pipeline gas sales, to preserve the benefits of "old" gas for existing firm sales customers and to mitigate competitive distortions resulting from the lingering effects of continued wellhead price controls.
- The first block would contain "old gas" under sections 104, 106(a), and 109 of the NGPA and would be available first to all existing firm sales customers of the pipeline; the second block would contain all other gas. All non-gas costs associated with purchasing gas would be billed under a third block. At present, the proposal does not specify an allocation mechanism for the third block and comments have been requested as to how this can best be done consistent with the Commission's objective of conveying appropriate price signals.
- This procedure would permit all pipelines to compete for marginal markets and additional sales on the basis of current prices being paid for gas supplies, not on the basis of rolled-in pricing of forever price-controlled gas.

- When a pipeline has permitted its firm sales customers to reduce their contract demands by 100 percent and offers those customers nondiscriminatory self-implementing transportation, then, subject to a transition period, the rates charged by the pipeline for natural gas assigned to the second block would be presumed to be just and reasonable.

The reasons underlying this proposal are detailed below.

CURRENT NATURAL GAS MARKETS

A. The NGPA and Its Effects on the Natural Gas Industry.

In November of 1978, Congress enacted the NGPA. As noted by the U.S. Supreme Court, the NGPA "has been justly described as 'a comprehensive statute to govern future natural gas regulation.'" In adopting the NGPA, one of Congress' "motivating purposes" was "to eliminate the dual market that distinguished between interstate and intrastate sales of natural gas."

This integration of the two markets was to be established by a scheme of gradual removal of federal price controls over natural gas at the wellhead (NPGA Title I and section 601(a)(1) and (b)(1)) and by the provision for more efficient transportation of natural gas (NGPA Title III and section 601(a)(2)).

In short, the NGPA set in motion a gradual transition from a regulatory scheme in which interstate natural gas was subject to federal regulation from the wellhead to the city-gate to a scheme whereby wellhead and burner-tip prices are increasingly set by market forces, even though interstate pipelines remain subject to regulation under the NGA.

Developments over the last six years have moved the natural gas industry significantly along in this transition. Since 1978, wellhead prices have risen, encouraging the development of new supplies of natural gas. At the same time, rising prices have provided incentives for users of gas to conserve, employ more fuel-efficient equipment, or even shift to alternate fuels, thereby cutting back on demand. After the sharp increases from 1978 to 1982, average wellhead prices stabilized in early 1983 and have remained relatively stable during the last two years.

One result of the rapid supply and demand changes under the NGPA was the appearance in 1982 of a substantial surplus of gas deliverability. This surplus translated into significant take-or-pay exposure for many interstate pipelines. As the price of natural gas in the "spot" or short-term markets fell below the price of gas in the long-term or "contract" market, demand for transportation services also tended to increase.

Equally significant have been changes that have occurred at the other end of the pipeline. Economic forces, in the form of declining oil prices and improvements in electricity-using technologies, have created strong and viable competition for end uses in many markets previously dominated by natural gas. The effect of these events has been to increase market competition at both ends of many pipelines.

The competitive pressures caused by partial wellhead deregulation continue to grow and have become even more evident since January 1, 1985. Demand for transportation services to reflect the growing competition at both wellhead and burner-tip can also be expected to increase. Greater customer access to alternate suppliers and/or transporters of gas is giving rise to innovative marketing strategies both by new entrants to the natural gas sales business as well as by traditional suppliers. Alterations in the way risks are shared, more open access to transportation and concomitant changes in service agreements, and new gas purchase policies are reflections of and responses to fundamental changes which have already occurred in natural gas markets. These new ways of doing business in response to market forces have important implications for the way the industry is regulated, and have made necessary our proposal for timely regulatory adjustments.

B. The Problem in a Nutshell.

As these changes in the industry have occurred, a number of problems have been brought to the Commission's attention:

1. Many interstate pipelines have contracted for more gas supply than can be marketed at the prices set forth in those contracts.

2. Producers of gas, responding to very high prices for supplies of deregulated gas, have developed new supply sources of gas. But since the market could not absorb these quantities

at prevailing prices, a surplus has been created, resulting in many wells being shut-in and in producers -- particularly independent producers -- seeking alternative markets for their gas.

3. Pipelines have sought alternative markets as well and sought out new customers. But the existing customers of the pipelines have been concerned that so-called "off-system" sales would effectively transfer to the new customers a portion of the economic rent associated with the old, price-controlled gas. Reflecting these same concerns, the Commission generally has allowed these sales only under somewhat restrictive conditions.

4. Purchasers of natural gas, seeing the availability of supplies in the field at prices below the rolled-in average cost of pipeline supplies, have sought to purchase gas in the field and have it transported instead of purchasing the supplies which the pipelines have obtained under the now-uneconomic long-term contracts.

5. The pipelines have generally expressed a reluctance to provide transportation for such direct field purchases.

a. With respect to incremental volumes (i.e., gas that would not displace a sale by the pipeline itself from its own contracted-for supply), pipelines generally have not had adequate incentives to provide this service as long as the pipeline's rate structure required the crediting to the pipeline's sales customers of essentially all revenues received from the transportation. The regulations allowed the pipeline to elect an option pursuant to which costs would be allocated to the transportation service (allowing retention of the revenues), but until fairly recently most major pipelines had not elected that option. Moreover, the pipelines were under no legal obligation to elect the revenue retention option. As pipelines begin to design their rates to allocate costs to the transportation service, thereby obtaining the right to retain revenues, the ratemaking rationale for declining to transport incremental volumes has diminished.

b. With regard to volumes of gas that would displace a sale by the pipeline from its own contracted-for supply, the situation has been somewhat more complex.

(i) Where the pipeline's take-or-pay exposure was so great that it believed that prepaid gas would never be able to be "made up," the pipeline faced the possibility of forfeiting the entire principal amount of the prepayment. Under these economic circumstances, even where the pipeline was able to retain the revenues received from providing transportation, the pipeline would still lose money were it to transport gas that would displace a unit of contracted-for gas. The more gas it transported, the more money it would lose. Under these circumstances the pipeline's reluctance to transport was at its height.

(ii) Where the pipeline's take-or-pay exposure was not so great as to confront it with the prospect of forfeiting prepayments, the question was more one of cost allocation. If the pipeline had to finance the prepayments, who should bear the burden of the carrying charges associated with the prepayment: the sales customers, the transportation customers, the producer (by not being paid in accordance with the contract), or the pipeline's shareholder?

6. A number of key aspects of the existing contractual arrangements in the industry from wellhead to city-gate tended in large part to allocate to the buyer the risk that the supply of the commodity might prove unmarketable at some point over the life of the contract. As a result, the average delivered price of gas has been slow to adjust downwards to transmit price signals more accurately that would help increase consumption and absorb the available excess supply.

7. This situation is resulting in a very large loss to the American economy in terms of net economic efficiency. In concrete terms, this has meant a drag on the competitiveness of American products in world markets, lost jobs, lost production, and unnecessarily high energy costs to all customers. It has contributed to distortions in the financial markets and to the inefficient allocation of scarce investment capital by encouraging the over-investment in what now appear to be uneconomic energy supplies.

8. As a result, it appears that the current regulatory practices now tend to result in rates for the jurisdictional sales or transportation of natural gas that may not be the lowest reasonable rates consistent with reliable, long-term supply.

C. How the Commission Proposes to Address the Problem.

The proposed regulations are intended, for the most part, to supplement existing Commission regulations and provide additional options to interstate pipelines that seek increased flexibility in offering those services that their customers wish to purchase.

The proposed regulations permit pipelines to enjoy greater flexibility and the opportunity for increased returns as long as the pipeline is willing to assume the economic risks of underrecovery of costs.

With one notable exception, there is no requirement in this proposal that would be imposed involuntarily on any pipeline. Rather, a pipeline that so desires would remain free to offer natural gas sales and storage services in which the transportation component of the service is part of a package or "bundle" of services. The various access and rate conditions would only apply if the pipeline chose, after the effective date of the proposed rules, to hold itself out as a transporter of gas for others under the simplified program.

The exception is the requirement that all pipelines separate out, for billing purposes, their supplies of "old" gas. Under this three-part billing mechanism, the subsidy associated with the old, price-controlled gas would be effectively allocated to the historical customers. This requirement is intended to help "level the playing field" by requiring all pipelines to compete for new markets on the basis of their current cost of new gas supplies unaffected by their relative shares of older, price-controlled supplies.

Generally stated, these proposed regulations seek to achieve the following goals:

1. Non-discriminatory access to transportation.

A pipeline that chooses, after the effective date of the proposed rules, to hold itself out as a transporter of natural gas for others should offer that service without discrimination to all shippers willing to pay appropriate cost-based rates.

2. Increased flexibility in offering new services and changing rates.

In those areas where competitive forces are adequate, the regulatory framework should allow all participants in the industry greater flexibility to adjust to market conditions so long as the adjustments do not involve cross-subsidization or the involuntary shifting of costs among customers. This flexibility should not preclude -- at the federal regulatory level -- the entry of new companies to serve existing loads, as long as the regulatory framework allows comparable flexibility to all competitors. We recognize that the prospect of new entry may raise issues of acute concern in some cases for individual localities. However, it is our tentative judgment, reflected in the proposed rules, that, under our system of federalism, state governmental authorities, not the Commission, are provided the discretion and authority to evaluate these issues and to strike the appropriate balance among competing local interests. We recognize that this may take time and we have provided a period of transition.

3. Establishing appropriate levels of company accountability.

The more competitive environment that has begun to emerge for the pipeline industry has required firms within the industry to respond in new and innovative ways. For the Commission to allow regulated companies to respond flexibly and quickly to these requirements (by authorizing new ventures, or allowing companies to alter the way in which some traditional service has been rendered because of an unregulated entity's market threat) the pipeline must be held accountable for such decisions. To do otherwise is to eliminate a very powerful incentive to reasoned and rational behavior on the part of pipeline companies, and require more explicit regulatory requirements and oversight instead.

Common sense and economic theory both suggest that putting a firm at risk for the consequences of its investment and operational decisions can affect the incentives to undertake those decisions judiciously: a firm is more likely to work to minimize its costs if its financial health is at stake than if its costs, even some fraction of its costs, are guaranteed. It is generally accepted that the potential for profit and the fear of financial loss create strong incentives for firms to hold down costs. Thus, pipelines that bear significant business risk, that is, firms that are ultimately accountable for their business decisions, are more likely to operate efficiently than are those firms that bear little or no risk. This aspect of policy implementation in the current rulemaking is reflected in the ratemaking design requirements as well as the Commission's willingness to grant competing certificates when pipelines demonstrate a willingness to assume all risk of the certificated activities.

4. Adjustment of service agreements and service obligations.

Existing certificate obligations and individual service agreements were largely developed in an era of wellhead price controls when natural gas was the cheapest fuel. Markets were largely supply or capacity constrained rather than demand constrained. With the gradual lifting of those controls, conditions have changed; it now appears appropriate to provide an opportunity to pipelines and their customers to make necessary adjustments to better reflect current conditions, especially where a pipeline is willing to assume these nondiscriminatory access conditions and open its system for transportation. This proposed policy is reflected in the proposed rules regarding customers' conditional rights to reduce their firm purchase entitlements and the provision for a corresponding pre-grant of abandonment to the pipeline.

5. Removing the remaining distorting effects of prior price controls.

For the proposed policies enumerated above to be effectively implemented, it is necessary to minimize the distortions still caused in current and future markets by past price controls on natural gas at the wellhead. It is the Commission's tentative judgment that transitional policies should be adopted: (1) to provide regulatory predictability to interstate pipelines seeking to resolve future take-or-pay exposure under so-called "problem contracts;" and (2) to require all pipelines to separately bill the old gas volumes to their customers while reserving to historical customers the benefits of that gas for which Congress saw fit to retain wellhead price control.

6. Regulations that are appropriate in times of rising as well as falling commodity prices.

The proposed regulations are intended to establish a long-term regulatory framework -- not to be a reaction only to immediate circumstances. The measure of a good regulatory scheme is that it remain valid in all circumstances -- in times of shortage as well as surplus. To this end, the proposed regulation would establish a scheme that reflects and promotes competition, secures its benefits to natural gas consumers, and gives to natural gas companies the tools with which they can compete.

7. Clear and more accurate price signals.

Finally, the rule proposes three substantive policies with respect to the billing mechanism for a pipeline's purchase gas costs. First, consumers and producers shall see clear and more accurate price signals. Second, the playing-field on which pipelines compete will be leveled such that competition is fair and leads to economic efficiency. Third, the economic rents associated with "old" gas are preserved for a pipeline's traditional customers.

Currently, the rolled-in pricing of all gas purchases prevents these substantive policy objectives from being realized. Consumers are misled in their decisions on gas purchases and price signals are sent that natural gas is cheaper than the cost of purchasing additional increments. Producers, on the other hand, are given price signals that higher cost new gas supplies are marketable. Consumption decisions should be based on a more accurate cost of gas supply; production decisions should be based on a more accurate measure of the value of the gas supply.

Currently, interstate pipelines have a relatively uneven distribution of low-priced gas from old fields. Newer independent merchants typically do not have access to these lower-priced gas supplies at all. Thus, some firms may possess comparative advantages which are not based upon current operational efficiency. It is important that the playing-field be level so that competition leads to greater economic efficiency and not to expenditures for new transmission facilities or new gas supplies that would not be economic except for the one pipeline's relatively greater access to old gas.

This rule proposes a three-part billing mechanism for natural gas supply, in order to permit all pipelines to compete for marginal markets and additional sales on the basis of current markets for gas supplies, not on the basis of rolled-in pricing of forever price-controlled gas.

This proposed rule is intended to provide customers with a clearer understanding of the mix of gas being offered by the pipeline and of the real cost of incremental consumption. At the same time, the proposal would not change the total gas bill charged to current customers assuming their current purchased volumes remain the same.

OTHER REGULATORY DEVELOPMENTS

A number of other important natural gas regulatory issues besides the NOI and the proposed rulemaking have been before the Commission and the courts over the last 12 months. I will summarize several of these below.

A. NGPA - Mandated Deregulation.

The following categories of gas were deregulated on January 1, 1985, by section 121 of the NGPA: (1) section 102(c), new natural gas; (2) section 103, new onshore production wells, if the natural gas was not committed or dedicated to interstate commerce on April 20, 1977, and is produced from a completion location deeper than 5,000 feet; and (3) sections 105 and 106(b) intrastate contracts in excess of $1.00, i.e., natural gas sold under an existing intrastate contract, any successor to an existing intrastate contract, or any intrastate roll-over contract if such gas was not committed or dedicated to interstate commerce on November 8, 1978, and the price paid for the last deliveries of such natural gas on December 31, 1984, or, if no deliveries occurred on such date, the price that would have been paid had deliveries occurred on such date, was higher than $1.00 per million Btu.

In its deregulation rulemaking, the Commission amended its regulations to prepare for price deregulation under the NGPA. In general, these rulemaking orders addressed four major issues. First, the Commission decided that jurisdictional agency well category determinations are still necessary for sections 102 and 103 gas. Second, the Commission determined that first sellers may make interim collections at an agreed upon deregulated price. Third, the Commission found that gas that qualifies for both a regulated and deregulated category is deregulated. Finally, if the price charged for intrastate gas under a successor or existing contract was over $1.00 per MMBtu and the price was established under an indefinite price escalator clause, the gas is re-regulated under section 105(b)(3).

The Commission's orders are on appeal to the 10th Circuit. Martin Services, Inc., et al. v. FERC, Nos. 84-2756, 84-2760, et al. (10th Cir. filed Dec. 21, 1984). No briefing schedule has yet been established in the case.

B. The Order No. 380 Series.

The competitive forces unleashed by the NGPA would not be felt at the wellhead if pipeline customers were required to pay for certain quantities of gas, whether they purchased those quantities or not. Consequently, a year ago, the Commission issued Order Nos. 380 and 380-A, which prevent pipelines from charging for purchased gas costs for gas not taken by the buyer.

The Commission also determined that the same anti-competitive effects present in minimum bills -- provisions requiring customers to pay for gas whether they took the gas or not -- were also present in minimum take requirements. A minimum take, as the term suggests, requires that a customer take and pay for a certain quantity of gas. Thus, in Order No. 380-C the Commission proscribed minimum takes as well.

In these orders, the Commission concluded that minimum commodity bills enable a pipeline to recover purchased gas costs where the pipeline does not actually incur such costs. The Commission also found that if a customer must pay for the gas, whether or not it actually takes the gas, then the customer will not seek lower-priced gas supplies but will continue to purchase gas from the same supplier.

Petitions for review of these orders were filed in the D.C. Circuit, where the case has been fully briefed and argued and is awaiting decision.

C. Special Marketing Programs.

In 1983 and early 1984, in response to requests by pipelines and producers, the Commission approved various special marketing programs and sales programs ("SMP-1"). These SMPs were experimental and temporary in nature, and were authorized initially only through October 31, 1984.

Under the SMP programs, a pipeline with more gas under contract with a producer than it can use releases some of the gas it has under contract back to the producer who can then resell it. The program was designed initially to prevent loss of marginal customers, e.g., those with alternative fuel capacity, and did not permit customers other than marginal customers to participate in the program.

In the fall of 1984, on a continued experimental basis, the Commission authorized approximately 16 SMPs for an additional one year ("SMP-2"). SMP-2 contained many of the same conditions as SMP-1 and was authorized until October 31, 1985. However, the 1984 SMP-2 order differed from SMP-1 in regard to participation by firm sales customers other than marginal customers. SMP-2, unlike SMP-1, requires that firm sales customers be provided access to SMP gas for up to 10 percent of their contract demands.

A critical factor in the Commission's decision to authorize SMPs was take-or-pay relief. All the SMPs certificates provide that no gas may be released for sale under an SMP unless the producer or supplier absolves each releasing pipeline of take-or-pay liability for any volumes of gas sold and transported under the SMP. In deciding to extend the programs for up to a year, the Commission recognized that the programs have been successful in that releasing pipelines have been able to achieve significant take-or-pay relief.

The Commission had concluded that all customers would be helped by the SMP order. The Commission's basic rationale on this score was cost-spreading. Incremental volumes created by the program would result in lower per unit fixed costs. That is, if more gas were sold, the fixed costs would be spread over a bigger base, which would help captive customers as well as those participating directly in the SMP. Also, there would be a net decrease in take-or-pay obligations.

On May 10, 1984, on review, the D.C. Circuit Court of Appeals rejected the Commission's approach in approving a version of an SMP-1 program proposed by Columbia Gas Transmission Corporation in 1983 which restricted the availability of its SMP to marginal customers only. The Court assumed the additional SMP sales would still occur without any restrictions on the program at all. It disposed of the Commission's finding that incremental volumes would reduce take-or-pay liability on the same grounds -- that the incremental volumes would be purchased anyway. The Court also observed that customers would not necessarily pay take-or-pay costs. Indeed, it says, the pipeline may not even pay them. However, the Court did not have before it the current SMP-2 programs which include the provision for participation by firm sales customers.

The Court ordered the Commission to show cause why current SMP-2 programs -- which differ markedly from the earlier program reviewed by the Court -- should not be held to be invalid. On June 7, 1985, in its response to the Court's order, the Commission detailed the differences between SMP-1 and SMP-2 programs, especially in regard to the access of firm sales customers to SMP-2 programs.

D. Order No. 234-B "Blanket Certificate" Transportation Program.

In a companion case to the SMP case, the D.C. Court of Appeals vacated the Commission's short-term rule (promulgated in Order No. 234-B) that authorized interstate natural gas pipelines to transport gas purchased directly from a producer for "low priority" uses (such as boiler fuel). The rule automatically authorizes transportation of "low priority" direct-sale gas for up to 120 days, and provides that a longer period can be authorized after compliance with a notice and protest procedure. This rule, by its own terms, expires on June 30, 1985.

Maryland People's Counsel (Maryland) challenged the rule on the grounds that the Commission had failed to consider the impact of the rule on so-called "captive customers" (i.e., gas customers that are bound to purchase gas from an interstate pipeline because they have no alternative source of supply). In fact, Maryland argued, the rule would aggravate the situation of captive customers who were already paying higher than necessary gas costs, and would provide pipelines with a vehicle for engaging in price discrimination against captive customers in favor of fuel switchable customers.

On review, the Court found that Maryland's arguments had merit and that the Commission had failed to address these concerns. Consequently, the Court remanded the case to the Commission with directions to "fully consider and reasonably analyze the competitive concerns advanced" by Maryland. Order No. 234-B, 18 C.F.R. § 157.209(e), was vacated "to the extent that they do not allow transportation of direct-sale gas to fuel-switchable end-users without requiring pipelines to furnish the same service to local distribution companies and captive consumers on nondiscriminatory terms."

Senator NICKLES. Thank you very much, Mr. O'Connor.

Senator Ford, we welcome you. Did you have any opening comments?

Senator FORD. I'll save that time for Mr. O'Connor.

Senator NICKLES. OK. Mr. Boggs, do you wish to make your opening remarks?

STATEMENT OF HON. DANNY J. BOGGS, DEPUTY SECRETARY, DEPARTMENT OF ENERGY

Mr. BOGGS. Thank you, Mr. Chairman, members of the subcommittee:

I appreciate the opportunity to appear before you to discuss the current conditions in the natural gas market and factors affecting it. I will begin my testimony by outlining the initial progress that we have made under partial decontrol. I will then address some of the shortcomings of partial decontrol, and also our reaction to some of the recent activities of the Federal Energy Regulatory Commission. I will close with a discussion of additional actions that we believe would complete the transition to a fully competitive and efficient natural gas market.

With regard to current conditions, I think the most striking fact of the past 6 months has been that, contrary to the opinions often expressed by critics of natural gas deregulation on January 1 of this year, we have not had price increases in natural gas. Instead, partial decontrol increased competition and introduced greater price flexibility into the natural gas market. As a result, virtually all measures of natural gas prices have declined in real terms between 1984 and 1985 as predicted in the section 123 report submitted by the Department of Energy.

Many experts had predicted a large increase in prices, often referred to as a price flyup, upon partial decontrol. For example, less than a year ago the Citizens Labor-Energy Coalition claimed that natural gas wellhead prices would increase by about 15 percent in real terms from last year to this year. As late as last December, the Interstate Natural Gas Association indicated that price escalators could cause interstate gas prices to rise 9 to 12 percent in real terms from last year to this year.

To the contrary, almost every measure of natural gas prices has been falling in real terms. The prices I will give are in constant 1984 dollars. First, the FERC form 11 data on the prices paid to producers by interstate pipelines fell from $2.91 in 1984 to $2.81 the first 2 months of this year.

The purchased gas adjustment filings of 20 major interstate pipelines showed a projection of $2.85 in real terms in the last half of 1984 and an expectation that they would average $2.74 during 1985. A trade publication reporting spot prices in the major Texas and gulf coast region showed declines in spot prices of up to 15 percent from the end of last year through early June of this year.

The Energy Information Administration's data series on residential prices for the first 4 months of this year showed a decline from $6.07 during the first 4 months of last year to $6 in the first 4 months of this year.

Finally, the Producer Price Index, which we now have available for 5 months of 1985, shows about a 3-percent decline in real prices from the first 5 months of last year to the first 5 months of this year. In short, it has developed that there was nothing whatsoever to the fears of flyup.

The recent downward trend in natural gas prices, despite increased gas demand from the expanding economy, has to a large degree resulted from increased competition in the natural gas and energy markets following partial decontrol. We believe that full decontrol would provide even greater benefit in terms of lower consumer prices and higher economic growth. Although the partial price decontrol has yielded some benefits, remaining price controls on old gas and the complex regulatory system imposed on the industry will continue to distort the natural gas market and reduce the supply of gas available at competitive prices.

The natural gas market will not be able to adjust to changing market conditions fully and properly as long as price controls remain on old gas and access to gas transmission facilities is limited. Instead, these remaining market and regulatory distortions will impose unnecessary costs on consumers and the economy as a whole.

The continued presence of a gas surplus that appears to average about 2 trillion cubic feet during 1985 indicates that average gas prices are not at market-clearing levels. In a freely operating market, this would cause producers to be able to reduce their prices to sell excess supplies and encourage greater consumption at those prices.

In a market with open access to transportation services, pipelines and their system suppliers would have additional incentives to renegotiate prices since consumers would switch to spot market purchases if system supply prices remained high.

Chairman O'Connor has spoken of the past FERC proceedings and the recently issued notice of proposed rulemaking. The Department of Energy participated fully in those earlier proceedings. We urged the Commission to adopt a uniform nondiscriminatory transportation program without restrictive conditions. With respect to rate design and risk allocation, we urged a system that promotes competition and increases efficiency by encouraging greater utilization of available capacity and unbundling transportation services and costs.

Our comments to the Commission stressed the need for an approach that would ensure a clear and prompt transmission of price signals, and would not insulate pipelines from competition in the marketplace. The Department commends the Commission for its notice of proposed rulemaking and for moving quickly to make comprehensive adjustments to the regulation of natural gas transportation. We commend them in general on their efforts to promote competitive natural gas markets so that consumers are provided gas at the lowest reasonable rates consistent with reliable service.

We are now reviewing the specific components of the notice of proposed rulemaking and we will present specific comments in that proceeding when our review is complete. We intend to participate fully in that rulemaking.

In his State of the Union Address, the President reiterated his desire to fully deregulate all natural gas supplies. We believe the comprehensive deregulation of the natural gas market would provide large economic benefit to gas consumers in the U.S. economy. It is our hope that the evidence of increasing competition and falling gas prices since partial decontrol became effective will resolve concerns about price flyup, will demonstrate the basic soundness of deregulation, and will generate widespread support for comprehensive deregulation.

Remaining NGPA price controls prevent recovery of an enormous amount—we estimate 27 to 48 trillion cubic feet—of low-cost old gas. Recovery of these reserves could increase total production by almost 1 trillion cubic feet each year. Because of the average pricing system, old gas controls also subsidize excessive payments for high cost and imported gas supplies.

Partial deregulation during 1985 has reduced but not eliminated the subsidy. Therefore, prices under NGPA remain higher than they would be under complete wellhead decontrol, because total gas production remains lower and the gas that is produced costs relatively more.

The Department is now engaged in a decisionmaking process within the administration on the best means and legislation toward pursuing the President's policy on natural gas deregulation. The Department will also continue to monitor closely the trends in the natural gas market.

We look forward to working with Congress and the FERC to build upon the progress that has been achieved, and to provide consumers with even greater benefits from increased competition.

That concludes the summary of my statement, Mr. Chairman. I would be happy to answer any questions you might have.

[The prepared statement of Mr. Boggs follows:]

Statement

of

Danny J. Boggs
Deputy Secretary

U.S. Department of Energy

Before the

Committee on Energy and Natural Resources

Subcommittee on Energy Regulation and Conservation

U.S. Senate

June 18, 1985

Good morning Mr. Chairman and members of the Subcommittee. I appreciate the opportunity to appear before you today to discuss current conditions in the natural gas market and factors affecting it. I will begin my testimony by outlining the initial progress we have seen under partial decontrol toward a more competitive and efficient natural gas market. I will then address some of the shortcomings of partial decontrol, evidenced most strongly by the large volumes of low-cost, "old gas" that will never be produced under existing price controls, the continuing surplus of deliverable gas supplies, and the difficulties faced by many consumers in attempting to gain access to the least costly sources of natural gas. I will also describe some recent activities at the Federal Energy Regulatory Commission (FERC). Finally, I will close with a discussion of additional actions that we believe would complete the transition to a fully competitive and efficient natural gas market.

Contrary to the opinions often expressed by critics of natural gas deregulation, partial decontrol of wellhead prices on January 1 of this year has not caused increases in natural gas prices. Instead, partial decontrol increased competition and introduced greater price flexibility into the natural gas market. As a result, prices to consumers have declined in real terms between 1984 and 1985, which is what the Department of Energy had predicted.

Many "experts" had predicted a large increase in prices, often referred to as a price "fly-up", upon partial decontrol. For example, in July of 1984 the Citizen/Labor Energy Coalition claimed that average natural gas wellhead prices would increase by 20 percent in nominal dollars (or about 15 percent in real terms) from 1984 to 1985. Most of this increase was attributed to indefinite price escalators in producer/pipeline contracts that theoretically would be triggered by partial decontrol. As late as December of 1984, the Interstate Natural Gas Association of America (INGAA) also asserted that indefinite price escalators could cause interstate gas prices to rise by 9 to 12 percent in real terms from 1984 to 1985.

To the contrary, natural gas prices are falling in real terms (all real prices are in 1984 dollars). For example:

(1) FERC Form-11 data indicates that prices paid to producers by interstate pipelines declined by 3 percent in real terms from 1984 through the first two months of 1985. In 1984 dollars, gas prices fell from an average of $2.91 per mcf in 1984 to $2.81 per mcf in January and February of 1985.

(2) From January through May of this year, the Purchased Gas Adjustment (PGA) filings of twenty major interstate pipelines projected that wellhead purchased gas costs would fall by 3.7 percent in real terms from late 1984 through 1985. The projected purchased gas costs of these pipelines were $2.85 per mcf in real terms in the last half of 1984 and are expected to average $2.74 per mcf during 1985.

(3) A trade publication has reported that gas spot market prices have declined during 1985.[1/] In Texas and the Gulf Coast region, spot prices fell in real terms from a range of $2.72 to $3.25 per mcf in early December 1984 to $2.36 to $2.55 per mcf in early June 1985, a decrease of 15 to 20 percent.

(4) The Energy Information Administration (EIA) has released data showing a slight decline in residential gas prices

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[1/] Natural Gas Intelligence, "Natural Gas Wellhead Prices," p. 10, December 10, 1984, and p. 10, June 10, 1985.

from 1984 to 1985. In real terms, residential prices dropped from $6.07 per mcf during the first four months of 1984 to $6.00 per mcf during the first four months of 1985.

From 1983 to 1984, total U.S. consumption rose from about 16.8 trillion cubic feet to about 17.5 trillion cubic feet. EIA projects that total consumption for 1985 will further increase to about 18 trillion cubic feet of gas. Most of this growth in consumption resulted from increased economic activity; little or none of this increase can be attributed to weather conditions, as the number of heating degree days fell 2 percent from 1983 to 1984. These gains have also resulted from lower gas prices due to contract renegotiations and spot market sales. The recent downward trend in natural gas prices, despite increased gas demand due to the expanding economy, has to a large degree resulted from increased competition in the natural gas market following partial decontrol. Full decontrol would provide even greater benefits in terms of lower consumer prices and higher economic growth. The following factors are responsible for the increased competition and greater efficiency observed since partial decontrol:

-- competition between natural gas and alternative fuels, such as residual fuel, primarily in industrial energy markets.

-- competition between deregulated gas and higher-priced regulated gas supplies.

-- competition induced by market-based pricing policies for imported Canadian gas.

-- competition between gas suppliers, especially the competition between discounted supplies sold in the burgeoning spot market and higher-cost pipeline system supplies.

-- competition among pipelines for sales to distribution companies. FERC recently prohibited pipelines from charging distribution companies for gas costs not actually incurred. This decision has made it much easier for distribution companies to switch to lower cost pipeline suppliers.

Although partial price decontrol has yielded some benefits, remaining price controls on old gas and the complex regulatory system imposed on the industry will continue to distort the domestic natural gas market and reduce the supply of gas available at competitive prices. These controls and regulations also have encouraged anticompetitive behavior by pipeline companies, in particular, refusal to transport gas for others even though excess capacity is available. This has contributed to the artificially high prices and the large volumes of unmarketed gas of the past several years.

The natural gas market will not be able to adjust properly to changing market conditions as long as price controls remain on old gas and access to gas transmission facilities is limited. Instead, these remaining market and regulatory distortions will impose unnecessary costs on consumers and the economy as a whole.

The continued presence of a gas surplus that will average from 1.5 to 2.3 trillion cubic feet during 1985 indicates that average gas prices remain above market clearing levels. At current prices, less gas is consumed than producers are willing to sell. In a freely operating market this would cause producers to reduce their prices to sell off the excess supplies.

In a market with open access to transportation services, pipelines and their system suppliers would have additional incentives to renegotiate prices since many consumers would switch to spot market purchases if system supply prices remained high. Pipelines are able to shut-in low cost gas supplies because regulations have allowed them to restrict access to available transportation capacity and thus avoid competition for shut-in supplies. Current regulations also allow pipelines to prevent core market customers from switching to lower cost gas suppliers.

Recent Developments

The Federal Energy Regulatory Commission has been sensitive to the market distortions I have described and has taken actions in an attempt to deal with them. Initially, these actions were not comprehensive. I have previously noted, for example, the minimum bill order.

Late last year, the Commission began a more comprehensive approach. In a Notice of Inquiry, the Commission sought comments on transportation, rate design, and risk allocation issues. The DOE participated fully in this proceeding. With respect to transportation, we urged the Commission to adopt a uniform, nondiscriminatory program, without restrictive conditions. With respect to rate design and risk allocation, we urged a system that promotes competition and increases efficiency by encouraging greater utilization of available capacity, and "unbundling" transportation services and costs. Our comments stressed the need for an approach that would ensure clear and prompt transmission of price signals and would not insulate pipelines from competition in the marketplace.

On May 30, 1985, the Commission issued a Notice of Proposed Rulemaking which would significantly alter four areas of pipeline regulation: 1) transportation on behalf of others; 2) payments on take-or-pay liabilities; 3) certification of new pipeline facilities and; 4) the treatment of gas costs.

Specifically, the Commission proposed a simplified program of transportation (for others) that includes blanket certificates for gas transportation under the condition that the pipeline provide non-discriminatory access to its transmission system. This transportation would take place under a volumetric rate design that is based on target volumes and is adjusted for peak and off-peak service. Participation in this program is voluntary, and a pipeline may choose not to take part.

The Commission also proposed a rebuttable presumption of prudence for payments by a pipeline to extinguish take-or-pay liabilities if the pipeline chooses to participate in the non-discriminatory transportation program.

The Commission further proposed an expedited certification procedure for new services, facilities and operations to the extent pipelines are willing to accept the risks of less than full recovery of fixed costs. Rates for these ventures would also be volumetric.

Finally, the Commission proposed a three part gas rate that separates old gas from other gas supplies and reserves the benefit of this gas for existing firm service customers.

We are in the process of completing our analysis of the Commission's Notice of Proposed Rulemaking (NOPR) and will comment prior to the deadline. We commend the Commission for moving quickly to make comprehensive adjustments to the regulation of natural gas transportation and commend them in general on their effort to ensure viable and competitive natural gas markets so that consumers are provided natural gas at the lowest reasonable rates consistent with reliable service. With respect to the specific components of the NOPR, we are now reviewing it to make sure we understand the ramifications of their proposal. We are unable to present specific comments until our review is complete. We intend to participate fully in the rulemaking proceeding and will address the specifics of the FERC proposal at that time.

Comprehensive Deregulation

In his State of the Union address the President reiterated his desire to fully deregulate all natural gas supplies. We believe that comprehensive deregulation of the natural gas market would provide large economic benefits to natural gas consumers and the U.S. economy. It is our hope that the evidence of increasing competition and falling gas prices since partial decontrol became effective will resolve any concerns about price fly-up, and will generate widespread support for comprehensive deregulation.

Remaining NGPA price controls prevent recovery of 27 trillion to 48 trillion cubic feet of low-cost, old gas reserves. Recovery of these reserves could increase total U.S. gas production by almost one trillion cubic feet each year. Because of the average pricing system of gas pipelines, old gas price controls also subsidize excessive payments for high-cost and imported gas supplies. Partial deregulation during 1985 has reduced, but not eliminated, this subsidy. Therefore, prices under the NGPA remain higher than they would be under complete wellhead decontrol because total gas production remains lower and the gas that is produced costs relatively more.

The Department will continue to closely monitor trends in the natural gas market. We look forward to working with Congress and FERC to build upon the progress that has been achieved, and to provide consumers with even greater benefits from increased competition.

Senator NICKLES. Thank you, Mr. Boggs.

Mr. Boggs, you mentioned the administration's support for decontrol. I'm sure that you're aware that Senator Johnston has a bill in. I introduced a bill. Parts of those bills are similiar. I address the issue of price, as well. Both of them eliminate the Fuel Use Act and incremental pricing. I'm assuming the administration would be supportive of those efforts?

Mr. BOGGS. Well, Mr. Chairman, as you say there have been a number of bills introduced. There are a number of bills in the House. We are trying to take a comprehensive look at all of those bills, and at our own desires and philosophy, and come out with a single position on either legislation to introduce or legislation to support. There obviously are a number of different aspects. None of the bills that I have seen go immediately to complete deregulation; they all address different aspects of it in different fashions, and until we've completed that review I wouldn't like to comment on any given bill to say we support it or we don't support it.

Obviously we do support full deregulation. We in general support as much deregulation as we can work out with Congress, but we want to make that comprehensive review of the various proposals, as well as proposals within the administration, and we would hope to complete that in a reasonably short timeframe.

Senator WARNER. If the Chairman would yield?

Senator NICKLES. Certainly.

Senator WARNER. That's a very skillful answer. [Laughter.]

Are we to deduct from that that there's a likelihood that the administration, after assessing the various positions, might come forward with their own bill?

Mr. BOGGS. I wouldn't say that's necessarily a proper conclusion. It might be that we would say that one bill or another that is out there strikes the best balance of what Congress is likely to do. Essentially that's the question that we're engaged in looking at.

Senator **Warner**. So you will—the administration will take the position this year, either on an existing bill or perhaps another one to come in, or a bill of its own?

Mr. **Boggs**. There's no question about that.

Senator **Nickles**. I appreciate that. Also——

Senator **Ford**. Mr. Chairman, since we're getting into this, I just want to announce: I'm against all of them that've been introduced so far. [Laughter.]

Senator **Nickles**. I'm glad to know we're going to be able to work together this year. [Laughter.]

Senator **Ford**. For a compromise.

Mr. **Boggs**. That's why we're engaged in a review.

Senator **Nickles**. So you will know, and so Senator Ford and others will know, the provisions of the bill that I introduced that dealt with that tough issue of old gas pricing, do not abrogate contracts. It basically just said: "As those contracts expire, or as they're renegotiated, or as they terminate, then they would be decontrolled." So, we would see decontrol as those contracts would work their course, and I hope that you'll take a very good, close look at that proposal.

Mr. **Boggs**. We certainly will.

Senator **Nickles**. I also hope you'll read the President's statement that he made in Oklahoma. [Laughter.]

Senator **Ford**. But that was to raise money for you. [Laughter.]

Senator **Nickles**. Mr. Boggs, you mentioned a bubble of about 2 trillion feet. There's a lot of speculation out in the field of the size of the bubble and how long it will last. Any comments on that?

Mr. **Boggs**. Well, we're now in, I think, about the 5th year of an 18-month gas bubble, and you can certainly get a wide range of analyses. I saw one by one of the analysts of the American Gas Association which, if I'm not misquoting him, said essentially, we'd like to have it go away, but where am I going to put it? That is to say, either you have to have demand increase sufficiently to remove it, or you have to have production decline. And I guess my best reading of the evidence is that certainly in the near-term—talking about a year or so—there is no evidence of those two factors being anywhere near enough to erase the bubble.

Obviously you have to look at it year by year. The Energy Information Administration puts out a survey every quarter, and I think the striking thing of that survey has been how steady it has been now for about the last 4 or 5 quarters.

[The information follows:]

Table 23. Estimated Surplus Natural Gas[a]

Date Surveyed	Volume Estimated as Available During Six-Month Period[b] (billion cubic feet)	Period During Which Surplus Deliverability Available
1981		
January	219	January 1981 - June 1981
March	437	April 1981 - September 1981
July	410	July 1981 - December 1981
October	242	October 1981 - March 1982
1982		
January	456	January 1982 - June 1982
April	864	April 1982 - September 1982
July	1,229	July 1982 - December 1982
October	1,189	October 1982 - March 1983
1983		
January	1,715	January 1983 - June 1983
April	2,605	April 1983 - September 1983
July	2,357	July 1983 - December 1983
October	2,077	October 1983 - March 1984
1984		
January	1,695	January 1984 - June 1984
April	1,897	April 1984 - September 1984
July	1,872	July 1984 - December 1984
October	1,506	October 1984 - March 1985
1985		
January	1,650	January 1985 - June 1985
April	1,896	April 1985 - September 1985

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[a] See Explanatory Note 14 for discussion of estimated surplus natural gas.

[b] The total estimated volume of surplus natural gas available during the 6-month periods may include some double counting. For example, if a pipeline company purchasing gas from a first supplier reports all gas in excess of system customer requirements as surplus, this pipeline company could have a contract with another company which is taking less than 100 percent of the contract quantity. Inasmuch as the second company has contract rights to the gas, it could report this same gas as surplus. Every effort to eliminate or minimize these occurrences has been effected.

Notes and Sources: See the last page of this section.

Mr. BOGGS. Obviously these are factors that you have to monitor closely, but I would say that right now we don't see those factors operating absent the kind of changes in the regulatory system that are needed.

Obviously, if price clears the market, then in effect that removes the bubble, and that's one way to remove it. The other way is, as I say, to have production decline, and we hope that doesn't occur, and we don't see any signs of it in the near term.

Senator NICKLES. Mr. Boggs, finally before I move over to Chairman O'Connor, you mentioned the administration was looking at the notice of proposed rulemaking. Would you submit to this committee, as well, your analysis of the proposed rule?

Mr. BOGGS. Certainly.

Senator NICKLES. I appreciate that.

[The information follows:]

THE SECRETARY OF ENERGY
WASHINGTON D C 20585

July 15, 1985

Mr. Kenneth F. Plumb
Secretary
Federal Energy Regulatory Commission
825 North Capitol Street, N.E.
Washington, D.C. 20426

Re: FERC Docket No. RM85-1-000
(Parts A - D)

Dear Mr. Plumb·

Pursuant to the Commission's May 30, 1985, Notice of Proposed Rulemaking in this docket, I am pleased to submit the comments of the Department of Energy.

Yours truly,

John S. Herrington

John S. Herrington

Enclosure

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol	)))	Docket No. RM85-1-000 (Part A - D)

COMMENTS OF THE UNITED STATES DEPARTMENT OF ENERGY

SUMMARY

DOE agrees with the Commission that the public interest lies in a truly competitive market and that regulations should work toward that goal. To that end, DOE advocates decontrol of old gas supplies, open access to non-discriminatory transportation service, and efficient rate design. DOE believes that the Commission's proposal would be a major step toward the accomplishment of these goals and toward the development of a fully competitive natural gas market in which consumers receive adequate supplies at reasonable prices.

Current regulations have prevented consumers from purchasing the least expensive supplies of natural gas, reduced domestic natural gas production, and increased the Nation's dependence on expensive and insecure oil imports. The Commission's proposal would reduce inefficiencies associated with current regulations and increase competition in the U.S. natural gas market. As a result, consumer prices should decline and our

dependence on oil imports should be reduced. For these reasons, the Department strongly supports the Commission's efforts and urges the Commission to act expeditiously to implement its proposal, with the modifications suggested in this submission.

Transportation Proposals

The Department believes the removal of restrictions on access to the existing transportation programs and the inclusion of anti-discrimination provisions in these programs are the most important aspects of the Commission's proposal. Open access to transportation service on a non-discriminatory basis would reduce barriers to competition and provide an effective medium for the communication of market signals between the wellhead and the burnertip. Effective market communication and free competition in all segments of the natural gas market would result in increased supplies at the lowest reasonable cost and more efficient pipeline operations. Accordingly, the Department urges the Commission to adopt the open access and anti-discrimination changes to the existing transportation programs without delay.

The Department also believes that the Commission's proposed transportation rate design represents a significant improvement over rates currently used for gas transportation. The

Department estimates that the economic benefits from this proposal, assuming costs are properly allocated by time of use, range from $1.2 to $4.9 billion. However, DOE is concerned that the proposed volumetric rates would not properly allocate capacity during peak periods, and may not always encourage pipelines to minimize costs or be indifferent between providing transportation and sales service. These concerns would be reduced by applying a reservation charge for capacity, by reviewing sales targets more frequently, and by applying a similar rate design to both sales for resale and transportation. The Department believes that the Commission could also achieve its goals by applying a rate design which satisfies the principles suggested by DOE in its submission to Phases II and III of the Notice of Inquiry.

Finally, the Department agrees with the Commission that pipeline customers should have the right to adjust their contract demands and that pipelines should be pregranted corresponding abandonments of their service obligations. These proposals would facilitate open and effective competition in all sectors of the natural gas market. DOE suggests, however, that the Commission modify its proposal to allow all consumers, not just those who purchase gas from pipelines operating under the new transportation certificates, to adjust their contract demand in the shortest period consistent with an orderly transition. The Department also suggests that the Commission pregrant abandonment of gas, particularly low cost old gas, which has been shut-in over a specified period of time. DOE believes that making this gas available to consumers, in conjunction with the transportation program, would create strong competitive pressure. These actions would ensure that consumers realize the full benefits of the Commission's proposal.

Take-or-Pay Settlements

The Department believes that the Commission is correct in placing primary reliance on increasing competition to encourage pipelines to participate in the proposed transportation program. Competitive market forces are solving problems encountered by those few pipelines that have incurred significant take-or-pay liabilities. DOE also believes that the Commission is correct in recognizing that the potential for future unmet take-or-pay obligations may discourage some pipelines from participating in the non-discriminatory transportation program. DOE also agrees with the Commission that the implementation of a consistent and well-defined regulatory policy toward these obligations would encourage more timely resolution of take-or-pay liabilities in negotiations between pipelines and their suppliers. The proposed rule would accomplish this by clearly stating the Commision's intention to accept reasonable cash settlements on take-or-pay obligations that are determined by competitive market forces in private negotiations. DOE also urges the Commission to examine individual circumstances to ensure that a pipeline used proper discretion in renegotiating its payments on take-or-pay obligations.

Expedited Certificates

The Department agrees with the Commission that reform of the Section 7 certification procedures is necessary and supports adoption of the proposed expedited certificates as a first step in this process. The Department agrees that there is no reason for protracted proceedings where a pipeline, or its potential customers, is willing to assume the full risks of a new venture. This risk ensures that those with the best information -- producers, pipelines, potential customers, and investors -- will fully evaluate each decision to construct new facilities and bring only those that are economically sound, and therefore in the public interest, before the Commission.

DOE also agrees that those protesting expedited certificates should have the burden of proving that the certificate would not serve the public convenience and necessity. DOE urges the Commission to extend this principle to protestors of all new facilities, including qualifying facilities such as sales taps that are authorized under other sections of the proposed rules. Competition is an essential element of the public interest and works to the benefit of consumers. A protestor should be required to demonstrate why competition would not serve the public interest in a particular situation.

Old Gas Billing Procedure

The billing procedure proposed by the Commission takes positive steps to eliminate economic distortions that result from rolled-in pricing and the unequal distribution of old gas among pipelines. The Department estimates that consumers and the U.S. economy could realize net economic benefits of as much as $2.2 billion if the Commission's proposal is adopted.

The Department is concerned, however, with a number of risks that arise in implementing this proposal. DOE believes that there are serious questions whether the potential benefits of the billing proposal outweigh the risks associated with allocating old gas entitlements to historical firm-service customers. DOE is also concerned that the effectiveness of the Commission's proposal would be reduced if distributors continue to roll-in the price of their old gas purchases with their other purchases. This proposal may also create incentives for distributors to capture rents by expanding their rate base. A small but inefficient increase in distribution margins could easily eliminate the benefits of this proposal.

Finally, the Department notes that this billing mechanism does not eliminate the major economic losses caused by price controls on old gas. The Department remains fully committed to decontrol of all natural gas prices.

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APPENDIX A

APPENDIX B

INTRODUCTION

The Department of Energy (DOE) is pleased to comment in response to the Commission's Notice of Proposed Rulemaking on the Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol. DOE strongly supports the Commission's goal to make the natural gas industry more responsive to the competitive pressure in today's market. The Commission's proposal is a major step toward achieving that goal. Set forth below are DOE's reasons for supporting the Commission's efforts to achieve a more competitive marketplace for natural gas. In addition, DOE suggests modifications to several aspects of the Commission's proposal, as well as additional actions that would increase the role of competition.

BACKGROUND

Partial wellhead price deregulation, surplus deliverability, relatively low prices for alternative fuels, and the development of a natural gas spot market are all exerting strong competitive pressure on today's natural gas market.1/ But American

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1/ DOE's "Increasing Competition in the Natural Gas Market: The Second Report Required by Section 123 of the Natural Gas Policy Act of 1978" (hereinafter "Increasing Competition") (DOE/PE-0069, January 1985) contains a full discussion of conditions in the current natural gas market. Increasing Competition was attached as an appendix to DOE's comments concerning Phase I of the Notice of Inquiry in this docket.

consumers are not receiving the full benefits of these competitive forces, and are paying too much for natural gas. This frustration of competitive forces is attributable to the existing regulatory framework which permits and, in some instances, encourages anti-competitive behavior.

The public interest is not well served by the existing regulatory framework. The Natural Gas Act (NGA) was not adopted to insulate the natural gas market from competitive forces. Quite to the contrary, Congress adopted the NGA to protect consumers from monopolistic practices by pipelines. The Natural Gas Policy Act (NGPA) endorsed the role of competition in natural gas markets by partially deregulating wellhead prices and by facilitating sales and transportation arrangements.

A. TRANSPORTATION PROPOSALS

1. Non-discriminatory Transportation Program

Commission Proposal

The Commission is proposing an open access, non-discriminatory, voluntary transportation program. Specifically, the Commission's proposal would modify the existing blanket certificate program under section 7 of the NGA and the transportation programs under section 311 of the NGPA to require a pipeline to offer service on a non-discriminatory basis if it chooses to transport gas for others under these programs. The proposal also would provide open access to the existing programs by removing the existing restrictions concerning the types of gas and end-uses for which service is available under these programs.

All arrangments of 120 days or less for the proposed transportation service would be authorized automatically, while arrangements for longer periods would be authorized subject to notice and protest procedures. The charges for the proposed service would be determined under a new volumetric, rate design.

DOE Comments

DOE fully supports the Commission proposal to modify the existing section 7 blanket certificate program and section 311 transportation programs so that they provide for open access to non-discriminatory transportation service. Recent years have witnessed significant changes in the natural gas market. Competition has grown increasingly strong at both the wellhead and the burnertip. While this has resulted in lower prices and more supply, the full benefits of competition have not been achieved. Natural gas prices, especially those paid by residential customers, remain high, while a large surplus of deliverable gas supplies persists in the field.

DOE believes the frustration of competitive forces is due in large part to the existing regulatory framework, which establishes the conditions under which pipelines can transport gas for others. 2/ Although transportation for others has increased in recent years, it has not served the broad

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2/ DOE's comments in response to Phase I of the Notice of Inquiry in this docket contain a fuller discussion of the relationship between existing transportation programs and the distortions in the current market. See pp.2-8 of Phase I Comments.

interests of all consumers in obtaining least-cost gas supplies. Rather, individual pipelines have provided this service to retain load and reduce take-or-pay exposure and inventory imbalances. The existing regulatory framework permits transportation for others to serve the needs of individual pipelines rather than the broader public interest primarily because of (1) restrictions on the availability of service and (2) the discretionary nature of the service.

The existing transportation programs contain many restrictions on the types of gas and end-uses for which the programs are available. While these restrictions were intended to protect consumers, especially the so-called "core market" consumers, they serve in practice to prevent the benefits of competition from reaching these "protected" consumers. The core market restrictions illustrate this point clearly. These restrictions prevent core market customers and the local distribution companies which serve them from obtaining low-cost gas supplies directly at the wellhead. At the same time, they insulate the pipeline supplying these customers from competitive pressures to offer low cost service, in the form of lower gas prices and more efficient pipeline operations.

The effectiveness of the existing transportation programs also has been limited by their discretionary nature; that is, the freedom of pipelines to choose whether, under what circumstances, and for whom they will transport gas. As private carriers that profit from natural gas sales, pipelines have strong incentives to prevent consumers from gaining access to other suppliers. As a result, consumers have been prevented from purchasing least-cost gas supplies.

Sections 4 and 5 of the Natural Gas Act clearly prohibit unduly discriminatory or preferential rates or services. [3] In the past, when pipelines acted primarily as gas sellers and offered little transportation to end users, the Commission could fulfill its duty under sections 4 and 5 by reviewing individual transportation arrangements. As transportation for others grows in volume and plays an increasingly significant rôle, these sections require the inclusion of an anti-discrimination provision within any program that generically authorizes transportation for others. [4] DOE believes the adoption of an anti-discrimination provision is essential, in the context of a voluntary program, to protect consumers from monopolistic behavior by pipelines and to ensure that consumers receive the full benefits of competition. [5] In Maryland People's Counsel v. Federal Energy Regulatory Commission, No. 84-1090. (D.C. Cir., June 28, 1985) the D.C. Circut vacated parts of the existing blanket certificate program "which permit pipelines to transport gas at reduced prices to 'noncaptive consumers' -- large industrial end-users capable of switching to alternate fuels -- without any obligation to provide the same service to 'captive consumers,' a group that includes local distribution companies and their residential customers." Slip opinion at p.4.

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[3] Section 4(b) of the NGA provides:

> No natural-gas company shall, with respect to any transportation or sale of natural gas subject to the jurisdiction of the Commission, (1) make or grant any undue preference or advantage to any person or subject any person to any undue prejudice or disadvantage, or (2) maintain any unreasonable difference in rate, charges, service, facilities, or in any other respect, either as between localities or as between classes of service.

Section 5(a) of the NGA provides:

> Whenever the Commission, after a hearing had upon its own motion or upon complaint of any State, municipality, State commission, or gas distributing company, shall find that any rate, charge, or classification demanded, observed, charged, or collected by any natural-gas company in connection with any transportation or sale of natural gas, subject to the jurisdication of the Commission, or that any rule, regulation, practice, or contract affecting such rate, charge, or classification is unjust, unreasonable, unduly discriminatory, or preferential, the Commission shall determine the just and reasonable rate, charge, classification, rule, regulation, practice, or contract to be thereafter observed and in force, and shall fix the same by order.

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[4] The Commission's responsibility under sections 4 and 5 is not confined to the programs affected by this proposal. DOE believes that in the context of today's market a pipeline should have the burden of showing why an anti-discrimination provision should not be included in any new section 7 certificate. In addition, the Commission should consider the inclusion of anti-discrimination provisions in existing certificates.

[5] The Commission's responsibility under section 4 and 5 will not end with the adoption of anti-discrimination provisions. DOE understands the Commission's desire to carry out its statutory obligations with a voluntary approach. The Commission's broad mandate to act in the public interest, however, requires a continuing review of pipeline behavior, and when necessary, the consideration of any and all additional actions (including mandatory contract carriage) necessary to achieve a truly competitive market which best serves the interests of consumers. See pp. 18-22 of DOE's Phase I comments.

DOE believes the removal of restrictions on access to the existing transportation programs and the inclusion of antidiscrimination provisions in these programs are the most important aspects of the Commission's proposal. Open access to transportation service on a non-discriminatory basis will reduce barriers to competition and provide an effective medium for the communication of market signals between the wellhead and the burnertip, as well as to pipelines. Effective market communication and free competition in all segments of the natural gas market will result in increased supplies at the lowest reasonable cost and more efficient pipeline operations. Accordingly, the Commission should adopt the open access and anti-discrimination changes to the existing transportation programs without delay.

2. Volumetric Rate Design

Commission Proposal

The Commission is proposing downwardly flexible, volumetric rates for use with the new transportation programs and the expedited certificates. The proposed rates would recover only those costs attributable to service under the new transportation programs of expedited certificates, and would separate these costs into charges for transportation, storage, and gathering. The transportation charge would allocate all fixed and variable costs volumetrically on the basis of projected transportation volumes. This charge would vary according to time of use (peak vs. off-peak periods) and distance transported. The Commission's proposal also would give a pipeline the flexibility to vary rates between a minimum rate and a maximum rate in both peak and off-peak periods. The minimum rate would be the short-run average variable cost and the maximum rate would be the minimum rate plus the per unit fixed cost for the peak or off-peak period.

Under the proposed rate design, a pipeline's initial filing could not include provisions that guarantee the recovery of fixed costs, such as minimum bill and minimum take provisions. Initial rates filed by pipelines also could not include demand charges. Further, pipelines would not be permitted to revise rates to recover revenue that may be lost if a pipeline chooses to lower the rate charged to a particular customer below the maximum rate.

If a pipeline filed rates for transportation that met the conditions described above, the Commission would consider an alternative rate design which includes other reasonable charges, such as a charge for reserving pipeline capacity, so long as the pipeline's customer(s) agreed to this condition.

By using volumetric rates for transportation, with rate targets based on projected volumes, the Commission seeks to create incentives for pipelines to minimize transportation costs and maximize throughput. To generate income or to increase profits, pipelines must seek to exceed the projected transportation volumes. The Commission also proposes that transportation rates should be flexible and [illegible], and should ration capacity during peak periods and maximize throughput during off-peak periods.

DOE Comments

DOE commends the Commission for moving in the direction of rates that encourage pipelines to provide service at minimum costs, that encourage consumers to make efficient decisions about the use of a pipeline's services, and that [illegible] to pipelines in exchange for the opportunity to earn profits. These objectives are similar to the general principles of efficient rate design recommended by DOE in its comments in Phases II and III of the Commission's January 16, 1986 Notice of Inquiry.[17] In its comments, DOE also recommended that rate design should make pipelines indifferent between selling system supplies and providing transportation for others. DOE believes that the transportation rate design proposed by the Commission represents a positive step toward satisfying these goals, and is an improvement over current rate design for natural gas transportation. Specifically, the Commission proposals provide economic benefits because it differentiates volumetric rates between peak and off-peak periods, provides for downward flexibility in rates, and unbundles gathering, transportation and storage charges.

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[17] See DOE's comments in response to Phases II and III of the Notice of Inquiry in this docket.

Benefits of the Proposed Rate Design. By properly allocating fixed costs to the peak period, the Commission would encourage more efficient use of pipeline capacity under transportation programs. DOE estimates that the adoption of this rate design would result in net economic benefits ranging from $1.2 billion to $4.2 billion between 1985 and 1995 for interstate pipeline transportation, alone.[7]

These benefits result from more efficient use of capacity under rates that encourage consumers to conserve their use of capacity during peak periods and expand their use of capacity during off-peak periods.

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[7] These estimates are lower bounds, since the current Commission rate design for transportation are volumetric rates that are not differentiated by time of use. Additional economic benefits would be obtained because the Commission would no longer credit transportation revenues to a PGA surcharge account. See Appendix A for a description of the models used to obtain these estimates.

By allowing pipelines to lower transportation rates for particular customers to short-run average variable costs, the proposed rates would introduce greater flexibility into natural gas pricing. This is important in a rapidly changing gas market, since pipelines may often wish to forego some transportation revenue to maintain or increase demand for their services. Allowing flexible rates would give pipelines the opportunity to do so.

By separately identifying transportation, storage, and gathering costs, the Commission also would effectively unbundle pipeline transportation rates. This would encourage consumers to make more efficient decisions about the use of pipeline services, since they could consider transportation, gathering, and storage costs in deciding where, when, and from whom to buy gas.

Concerns with Volumetric Rates. While the Commission's proposed transportation rates would improve existing rates and provide some economic benefits, DOE believes that greater economic benefits could be realized. Although the volumetric transportation rates proposed by the Commission put pipelines at risk for under-utilization of capacity, they do not allocate capacity efficiently during peak periods and they are highly dependent on projected representative volumes of transportation. In addition, by applying these rates to transportation only, the Commission may not make pipelines indifferent between providing transportation and sales service.

Even when properly differentiated by time of use, volumetric rates may result in excess demand for capacity during peak periods. In periods of excess demand, the Commission must set rules which ration pipeline capacity. If these rules are not based on price, they would not allocate capacity to those who most value access.

Volumetric rates do not necessarily allocate capacity-related fixed costs to those who incur them. Allocating capacity-related fixed costs on the basis of contract demand would require consumers to pay a larger capacity charge as they reserve more capacity. The level of capacity they would reserve would usually differ from average consumption, since consumers often reserve additional capacity to protect themselves against unusual events, such as unusually cold weather. When charged for their contract demand, consumers would reserve only capacity which they require and are willing to pay for. This is not the case under volumetric rates, where pipeline consumers possess no incentives to economize on contract demand.

DOE is also concerned with the effect of sales targets on pipeline behavior. These targets are based on both historical sales and on projected sales during the period in which the rate design goes into effect. In setting these targets, the Commission relies heavily on pipelines to determine projected sales. However, pipelines earn additional profits when sales exceed target levels. Thus, while these rate designs encourage pipelines to keep gas prices low to increase sales, they may not put pipelines at risk. The proposed rate design gives pipelines the opportunity to increase profits by underestimating the sales targets. In other words, reliance on sales targets could cause pipelines to "game" the Commission to increase profits, instead of encouraging them to minimize costs.

Under current policies, volumetric rates based on sales targets would remain in effect for up to 36 months. If the Commission wished to change the target before the pipeline filed a new rate case, the Commission could file a Section 5 rate case. Under a Section 5 rate case, however, the burden of proof would be on the Commission to show that the sales targets used to set rates can be expected to deviate significantly from projected sales volumes. This could be particularly difficult for the Commission to demonstrate in a period of volatile demand.

Finally, DOE is concerned that the proposed rates may not make pipelines indifferent between sales and transportation. If the Commission applies different rate designs to transportation and sales for resale, some pipelines may prefer sales service over transportation service, especially if pipelines are at greater risk for recovery of fixed costs under the transportation rate design. If the pipeline perceives that it would profit more from sales service than transportation, it may refuse to participate in the transportation program or it may discourage demand for transportation in ways that are difficult and costly for the Commission to monitor. For example, the pipeline may provide more 'reliable' sales service and argue that transportation service is more difficult to provide.

Recommendations. The Department believes that the Commission could address some of these concerns. DOE commends the Commission for allowing pipelines to negotiate alternative rate designs with their customers. These rate designs could include such desirable elements as a reservation charge which serves to ration pipeline capacity during peak periods.[8/] Pipeline customers would agree to these charges since they value capacity and are willing to pay to reserve its use.[9/]

[8/] By using a reservation charge for capacity, the Commission may still place the pipeline at risk for the service which is not demanded, but also place customers at risk for accurate projections of their demand.

[9/] However, pipeline customers would not agree to such a charge if allocation rules based on a predetermined system of priorities were applied to natural gas transportation. High priority customers would be able to obtain their capacity requirement in periods of excess demand without paying a capacity reservation fee. Low priority customers would have a limited ability to obtain this capacity even if they negotiated this fee.

Because these charges could result in an over- or under-collection of revenues in the short-run, the Commission would have to determine the appropriate method to either recover costs or refund consumers. DOE will continue to work with the Commission to resolve these issues.

DOE also recommends that the Commission develop a methodology to set sales targets frequently and to take corrective actions when representative volumes differ significantly from actual sales. One possible policy would require pipelines to set new sales targets each year. This would reduce the uncertainty caused by setting targets based on projected volumes over a number of years.

Once the proper regulatory adjustments are made to transportation rates, the Commission should consider applying this rate design to sales for resale as well. This would reduce potential pipeline incentives to prefer one type of service over the other.

The Department believes that the Commission could also achieve its goals by applying a rate design which satisfies the principles suggested by the Department in its submission to Phases II and III of the Notice of Inquiry. One approach consistent with those principles would remove fixed costs from the commodity charge, charge only peak users for the capacity related fixed costs of the system, and allow for a fair and efficient distribution of the remaining fixed costs among all gas customers. DOE also suggested that the Commission could encourage pipelines to minimize transportation costs without relying on the use of pipeline sales targets. This could be accomplished by tying pipeline profits to economic performance, such as in the utilization of capacity.

3. Adjustment of Service Agreements

Commission Proposal

In conjunction with the proposed transportation program, the Commission is proposing adjustments to existing service agreements. Specifically, if a pipeline chooses to offer service under the proposed program, its customers would have the right to reduce their existing contract demands for firm sales service by up to twenty-five percent during each of the next four years. Abandonment of a pipeline's service obligation would be pregranted to the extent of such reductions by its customers.10/

10/ Although the proposal is not explicit, we assume reductions in minimum bill obligations would correspond to reductions in contract demand. The fixed costs that would have been recovered under the eliminated minimum bill obligation should be reallocated to another service, such as the service under the transportation program. Otherwise these fixed costs may be loaded onto those customers which retain contract demand.

DOE Comments

DOE agrees with the Commission that pipeline customers should have the right to adjust their contract demands in conjunction with the new transportation program and that pipelines should be pregranted corresponding abandonments of their service obligations. Adjustments of service agreements would facilitate new and renegotiated arrangements which better reflect the competitive nature of today's market and thus help consumers receive the full benefits of competition. DOE suggests two modifications to this part of the proposal.

First, the right to reduce existing contract demand for firm sale service should be available to the customers of all pipelines, not just those pipelines which choose to offer service under the new transportation program. Consumers should not be denied the benefits of the emerging competitive market merely because their existing supplier refuses to participate in that market. This modification would be especially important in the case of customers that are served by more than one pipeline, since another pipeline might be willing to offer transportation service under the new programs if a customer's current supplier would not. Indeed, in many instances, the potential entry of competitors in a market is sufficient to force existing firms to behave competitively. A current supplier should not be able to insulate itself from this competitive pressure.

Second, DOE sees no good reason why the adjustment of service agreements should be spread over four years. To the contrary, the industry has shown a marked ability to adjust to competition when necessary. Any impediments to full adjustment of service agreements, such as take-or-pay liabilities, can and should be resolved quickly. On the other hand, both pipelines and their customers will need time to make new arrangements. The Commission should allow adjustments to occur in the shortest perioo (possibly one to two years) consistent with an orderly transition.

4. Pregranted Abandonment

DOE believes the new transportation program would be more efficient if the Commission's proposal were expanded to provide for the pregranted abandonment of shut-in gas supplies.11/ Currently large volumes of gas, particularly low-cost old gas, are being shut-in. DOE believes the availability to consumers of this shut-in gas, especially the low-cost gas, in conjunction with the new transportation program, would provide strong competitive pressure. These low-cost supplies could

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11/ Shut-in gas would be defined as the volume of gas to which a first purchaser has a right to take, but has not taken over a specified period of time (possibly the previous year). If a producer chose to exercise the pregranted abandonment, it would be permitted to sell the shut-in gas free of NGA obligations subject to any applicable NGPA ceiling prices. Shut-in gas would be considered taken by the original purchaser for purposes of computing its take-or-pay liabilities.

replace higher-priced supplies of gas or alternative fuels currently being taken and result in lower prices for consumers. The availability of these low-cost supplies would shift gas production to a more efficient schedule where least-costly resources are produced first. Accordingly, DOE urges the Commission to pregrant the abandonment of shut-in gas.[12]

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[12] There may be other situations where pre-granted abandonment would be appropriate, for example, where a contract for gas expires and the existing purchaser is unwilling to pay a price the producer can obtain from another purchaser.

B. TAKE-OR-PAY

Commission Proposal

The Commission's proposal would establish the presumption that pipeline payments to producers to eliminate future take-or-pay obligations are prudent up to a fixed amount. The fixed amount would be a percentage of a pipeline's estimated take-or-pay liabilities in 1986 and 1987 from contracts entered into before January 1, 1982 (qualifying contracts). The Commission believes this rule is necessary to encourage pipelines to transport gas for others, particularly in those cases in which the transported gas displaces gas supplies under contract to the pipeline and increases the pipeline's obligations to pay for gas not taken.

To obtain a presumption of prudence for these lump sum payments to producers, pipelines would be required to accept a nondiscriminatory transportation certificate. Pipelines also would be required to renegotiate contracts settled and brought before the Commission, so that all future take-or-pay obligations created by those contracts are eliminated. Approved payments would be recovered in a pipeline's rate base over a five year period, with no added carrying charges or return on these payments.

The Commission requests comments on what percentage of a pipeline's settlement eliminating future take-or-pay obligations should be allowed to pass through to ratepayers, and on whether the proposed rule should be expanded to include take-or-pay liabilities incurred before 1986.

DOE Comments

Competitive market forces are solving the problems encountered by those few pipelines that have incurred significant take-or-pay liabilities. DOE's Second Section 123 Report pointed out that "with the possible exception of a few pipeline companies, contract renegotiation has essentially eliminated problems associated with existing take-or-pay obligations."[13]

DOE commends the Commission for placing primary reliance on increasing competition to encourage pipelines to settle outstanding obligations and to participate in the proposed transportation program, while recognizing that take-or-pay obligations can act as a disincentive to participation in some cases. DOE also commends the Commission for recognizing that regulatory uncertainty can slow renegotiation of take-or-pay obligations. We are concerned, however, that unless these issues are addressed carefully, additional distortions in the gas market may be created.

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[13] *Increasing Competition*, p. 64.

In the past, uncertainty about what would be allowed in the passthrough of pipeline take-or-pay prepayments has slowed private renegotiations of take-or-pay obligations. DOE commends the Commission for taking steps to reduce this uncertainty. The proposed rule would do this by establishing a presumption that pipeline settlements with producers are prudent up to a fixed amount. DOE agrees with the Commission that the proposed calculation should only establish a presumption of prudence--it should not be conclusive. The Commission should continue to examine individual circumstances to ensure that the pipeline used discretion in renegotiating its payments on take-or-pay obligations.

DOE also agrees with the Commission's assessment that pipelines often refuse to carry gas for others because such activity could increase pipeline take-or-pay obligations. Once a large number of pipelines begin to participate in the Commission's proposed nondiscriminatory transportation program, however, competitive pressures on pipelines to resolve remaining take-or-pay obligations quickly and effectively in private negotiations would increase.

DOE believes the Commission should reconsider whether all future obligations need to be included in the rule. The current natural gas deliverability surplus, and therefore the probability of significant unmet pipeline take-or-pay obligations, should be thought to narrow by the end of the 1980's.

Problems with Take-or-Pay Recovery. It would be difficult for the Commission to adopt a single take-or-pay recovery [illegible] for all pipelines. Circumstances among pipelines vary widely, and only a few pipelines have significant take-or-pay problems. To implement the proposal, the Commission would have to estimate two very important factors. First, it would have to estimate the total value of take-or-pay obligations, especially those in 1986 and 1987 that would be incurred under current contracts. Information on take-or-pay [illegible] is very limited and liabilities are dependent upon uncertain future market supply and demand conditions.

Second, the Commission would have to determine what settlements [illegible] in a competitive market. In many cases, the size of the settlement would be strongly influenced by the producer's estimation of all future take-or-pay obligations under the current contract. [illegible] [illegible] [illegible] [illegible] [illegible] [illegible] therefore, the producer [illegible] [illegible] a larger cost settlement.

[illegible] these estimates are [illegible], the Commission must determine what percentage of the [illegible] [illegible] of future take-or-pay obligations [illegible] would be [illegible] to [illegible] through the [illegible] [illegible] [illegible]. If the percentage is set too high, consumers would be [illegible] [illegible] [illegible] than [illegible] [illegible]. If the percentage is set too low, pipelines would not be allowed to recover legitimate costs.

The Commission's proposal would tend to raise the starting point for negotiated payments to whatever ceiling it has imposed. Under current market conditions, some pipelines have made large cash settlements on their obligations, while other pipelines in stronger bargaining positions have settled liabilities without cash payments. Under the Commission's proposal, however, there would be strong incentives for producers not to accept less than the minimum cash payment allowed by the Commission in all take-or-pay negotiations. Presumed prudence for partial recovery of those obligations also would reduce the incentives for pipelines, including those with relatively strong bargaining positions, to negotiate settlements below the payment level set by the Commission.

Setting a specified recovery percentage also may be ineffective. It is unlikely under current market conditions that significant take-or-pay settlement costs could be recovered through pipeline rates without offsetting losses in load. The willingness of some pipelines to forego recovery of PGA surcharges for past undercollection is evidence of this. Rather than risk diminishing their gas sales further, these pipelines have chosen to pass these costs on to shareholders instead of ratepayers.

Further, DOE is concerned that too high a recovery percentage may be required if there is an effort to eliminate all future take-or-pay clauses. The elimination of all take-or-pay would greatly increase producer risks, and therefore the settlements producers require. Although current minimum take levels may be distorted by past regulations, take-or-pay clauses serve a legitimate purpose in a competitive market. Producers would be reluctant to sign long-term contracts dedicating supplies to one or more purchasers, unless the purchasers are willing to share the risk that demand may fall short of anticipated levels.

There are also problems associated with setting percentage levels too low. Low percentages may discourage settlements that would be in ratepayers' interests, because of the pipeline's fear of inadequate recovery. Given the problems associated with setting percentages too high, however, DOE believes that the Commission should set the final percentages quite low and review settlements calling for higher percentages on a case-by-case basis.

Relationship to Transportation Program

DOE also believes widespread voluntary participation in the nondiscriminatory transportation program is likely without the proposed take-or-pay settlement procedures. The Commission wisely chose to include all transportation arrangements in its proposed nondiscriminatory transportation program so that pipelines would be encouraged to participate to earn transportation revenues. For all Class A and B interstate pipelines, transportation revenues have been substantial, totalling about $1.9 billion in 1983.[14] In addition, pipelines would be encouraged to participate in this program to compete for additional sales. Pipelines that refuse to carry gas for others could lose sales to competing pipelines, producers, and marketers using the nondiscriminatory transportation certificate.

Summary

Competitive market forces are solving the problem encountered by those few pipelines that have incurred significant take-or-pay liabilities. Nonetheless, if carefully implemented, FERC's take-or-pay settlement proposal could be a positive step in reducing regulatory uncertainty. As FERC removes remaining regulatory restrictions on access to available pipeline capacity, competitive pressures will lead pipelines and their suppliers to efficiently resolve remaining take-or-pay obligations through private negotiations that can be ratified by FERC.

14/ FERC Form 2 Data reported in EIA's Statistics of Interstate Natural Gas Pipeline Companies, 1983 November, 1984, Table 8.

C. EXPEDITED CERTIFICATES

Commission Proposal

The Commission is proposing optional expedited certification procedures under section 7 of the NGA for new services, facilities, and operations if a pipeline is willing to assume all the risk of a new venture. The proposed expedited certification procedures would be a voluntary alternative to the traditional procedures for securing a section 7 certificate. The expedited certificates would not be exclusive (that is, certificates for competing ventures would be granted). Abandonment of service under an expedited certificate would be pre-granted when the contract for the service expired if there is an alternative supplier of the service.

New services under optional expedited certificates would be subject to many of the same conditions applied to the proposed new transportation program, including a nondiscrimination provision and, volumetric rates.

DOE Comments

Reform of the existing lengthy and complex procedures for securing a section 7 certificate is necessary. The

Commission's proposal on expedited certificates for new service is a good beginning and should be adopted.[15]

New ventures, if economic, serve the public interest because they introduce more competition in the marketplace. There is no reason for protracted proceedings where a pipeline (or its potential customers) is willing to assume all the risks of a new venture. This assumption of risk by the pipeline protects the public interest, since no customer will bear any cost attributable to the new service unless it demands the new service. Placing new project sponsors entirely at risk for their proposals will serve the public interest in another way. The risks of the marketplace will ensure that those with the best information -- producers, pipelines, new customers, and investors -- will fully evaluate each decision about whether to build new pipeline capacity before the proposal is brought to the Commission.

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[15] As a second step, DOE urges the Commission to reform the existing section 7 certificate procedures. DOE does not believe that lengthy and complex proceedings are necessary for most certificate applications. This reform could include, under the Natural Gas Act (NGA) and the Administrative Procedures Act (APA), such things as limitations on time periods for hearings, ALJ decisions, anc Commission opionions. It also could include usage of "on the record" trial-type adjudications only in situations where there is a relevant and material factual issue genuinely in dispute and a trial-type hearing is necessary for a full and true disclosure of the facts. Under the NGA and the APA, trial-type hearings are not necessary to resolve policy and legal issues. Finally, the Commission could adopt presumptions for the existing procedures, such as a presumption in favor of those firms which are most willing to assume the risks of a project.

The NGA was adopted to curb monopolistic practices by pipelines and not to insulate pipelines from competition. [16] The proposed expedited certificate process would mitigate several anti-competitive features of the existing regulatory framework. The traditional process of granting a certificate to a single pipeline has tended to grant monopoly power to pipelines serving certain areas of the country, thereby reducing the benefits of competition for consumers. It has also created a presumption that ratepayers are obligated to ensure the recovery of costs associated with the government-approved project even if it later becomes underutilized. In this risk-free environment, where pipelines' fixed costs for underutilized facilities are automatically paid by remaining pipeline customers, pipelines have strong incentives to inflate their rate bases by continuing to carry underutilized assets on their books or by constructing exces facilities.

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[16] Section 7(g) of the NGA provide:

> "Nothing contained in this section shall be construed as a limitation upon the power of the Commission to grant certificates of public convenience and necessity for service of an area already being served by another natural gas company."

The expedited certificate proposal should not be rejected because of arguments that economies of scale in some cases may dictate that only one pipeline should serve a new market -- either because ultimate sales in the market would not cover the costs of several, competing pipelines, or because one larger pipeline would be more cost-effective. If economic factors indicate that only one pipeline should be built, then only one project would be able to secure adequate financing, suppliers, and customers. Investors would not provide funding for a project unable to secure enough sales to cover its costs, since they would absorb any losses attributable to unused capacity. Investors would examine the alternative pipeline investment opportunities and choose the lowest-cost project aimed at the best sales market, since that project would offer the highest return on investment. If a single pipeline would have significantly lower unit costs than several smaller pipelines, it is likely that potential sponsors would form joint ventures to build the larger pipeline.

The degree of risk the expedited certificate process places on some projects may be unacceptable to the project sponsors, and a new facility may not be built. This should not, however, be considered a negative outcome by the Commission. Market-based decisions not to build new pipeline capacity would indicate that sufficient pipeline capacity already exists and that the net benefits to a pipeline sponsor and its potential customers would not justify the investment and associated risks.

DOE agrees with the Commission that those protesting expedited certificates should have the burden of showing the certificate would not serve the public convenience and necessity. This burden also should extend to protestors of facilities, such as sale taps,[16] which are "qualifying facilities" for purposes of the proposed expedited expedited certification procedures, but are authorized under Subpart F, the blanket certificate rule. The burden should not be lifted (and lengthy proceedings triggered) merely because a protestor claims the new service will be in competition with the existing or potential service offered by the protestor. Competition is an essential element of the public interest and works to the benefit of consumers. A protestor should be required to demonstrate why competition would not serve the public interest in a particular situation.

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[16] Historically, protestors of new sales taps have been companies whose sales are threatened by these new sales taps. Existing companies, however, should not be threatened by new facilities if they are operating efficiently. New facilities have not been depreciated, and should not be able to provide service to the customer of another company at a lower cost unless that customer is bearing fixed costs he is not responsible for, or unless the facility originally serving that customer was improperly designed. If, on the other hand, existing companies are not behaving efficiently or competitively, new sales taps should be approved quickly to increase competition and lower the costs of both gas and transportation service.

Initial rates for service under the expedited certificates would be essentially the same as those for service under the new transportation program. The difficulties associated with volumetric rates could be lessened, however, since the pipeline and the customers for its new service may work out an alternative rate design for the new venture. The Commission should permit the pipeline and its customers great flexibility since both parties can voluntarily negotiate appropriate levels of risk to be born by each party, and no other customers will bear any cost of the service unless they demand the service.

Summary

DOE believes that the Commission's proposal on expedited certificates for new services serves the public interest by bringing more competition into the market place. There is no reason for protracted certification proceedings where a pipeline (or its potential customers) is willing to assume all the risks of a new venture. Any decision not to construct new facilities in this environment would indicate that sufficient pipeline capacity already exists and that the net benefits to a pipeline sponsor and its potential customers would not justify the investment and associated risks. DOE also agrees with the Commission that those protesting expedited certificates, including certificates for facilities, such as sales taps, should have the burden of showing that such certificates do not serve the public convenience and necessity. This burden should not be lifted simply because the protestor claims that the new service would compete with existing or potential services.

D. BILLING PROCEDURES FOR PURCHASED GAS

Commission Proposal

The Commission is proposing a new, three-part billing procedure that allocates old gas production to the historical firm-service sales customers of interstate pipelines. Under this proposal, pipelines would be required to separate old, decontrolled, and nongas purchase costs in their purchased gas adjustment (PGA) filings. These costs would be billed to pipeline customers under three separate blocks, including:

Block 1:	Old Gas Costs - volume-weighted average cost of gas purchased under NGPA Sections 104, 106(a), and 109.
Block 2:	Decontrolled Gas Costs - volume-weighted average cost of gas priced under all other sections of the NGPA and all comparable costs of imported gas either at the U.S. border or at the tailgate of the regasification plant.
Block 3:	Nongas Costs - all other commodity or demand costs not included in Block 1 or 2, as billed to the pipeline.

Pipeline sales customers who purchased gas under firm-service contracts in 1982, 1983, or 1984 would be entitled to purchase a share of Block 1 gas equal to their share of total pipeline firm-service sales from 1982 to 1984. New and interruptible gas customers would only be allowed to purchase Block 2 gas. For pipelines participating in the transportation program, Block 2 prices would be presumed to be prudent after a four year transition period.

DOE Comments

The billing procedure proposed by the Commission takes positive steps to eliminate economic distortions that result from rolled-in pricing and the unequal distribution of old gas among pipelines. By separately identifying old and new gas costs to pipeline purchasers, the Commission's proposal would provide consumers with a clearer signal of the cost of satisfying their demand for gas. As a result, consumers would pay the same price for their gas purchases at the wellhead as that received by producers, rather than an average price below that received by producers.[18/] This higher marginal price at the wellhead should reduce aggregate consumption of new, imported, and high-cost gas, and eliminate some of the uneconomic production that is supported by the old gas cushion under current regulations. DOE estimates that production of decontrolled gas would decline initially by about 400 billion cubic feet a year relative to current regulations.[19/] This difference in

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[18/] DOE has assumed in its analysis of the billing procedure that consumers face the same prices as distributors. To the extent that distributors resort to rolled-in pricing, the potential benefits of the Commission's proposal will be reduced. For a more complete discussion, see p. 50.

[19/] The change in production schedules under FERC's proposal would not alter the total amount of gas reserves that are ultimately recovered under either current regulations or the billing proposal. Instead, under the billing proposal, production would simply be shifted to a schedule in which more expensive resources are produced in later periods. Because the model used to derive this estimate only includes interstate pipeline purchases (about 12 tcf total), it underestimates the full effect of the billing proposal on decontrolled production.

production between current regulations and the billing proposal would decline to about 200 billion cubic feet a year by 1990.[22]

The proposed billing procedure would also reduce opportunities for pipelines to operate their transportation systems inefficiently by transferring the old gas cushion from pipelines to local distribution companies. This transfer would increase competitive pressures on the transportation costs of those pipelines that own significant volumes of low-cost old gas. All pipelines would be encouraged to compete for customers by reducing their transportation costs. This would discourage inefficient pipeline operations that had been supported by a pipeline's old gas cushion.

The Department agrees with the Commission that all nongas costs, for both domestic and imported supplies, should be placed in Block 3 and allocated appropriately among consumers. There should be no regulatory distinction between the treatment of domestic and imported gas supplies. A rate structure that properly allocates costs, such as the recent two-part tariffs for Canadian imports, promotes efficient gas use.[32] These tariffs are also consistent with U.S. gas import policy. DOE strongly endorses the Commission's proposal to pass these charges through to consumers in the same form in which they are billed.

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[22] In considering the NGPA, Congress was aware that price controls on old gas, in conjunction with rolled-in pricing, would encourage pipelines to bid higher, incentive prices for natural gas from new sources. *E.g.*, see pp. 99-100 of Part 1 of House Report No. 95-496, (95th Cong., 1st Sess.). The NGPA represents Congressional attempts to both stimulate production and preserve the benefits of price controls for consumers. While DOE agrees with the Commission that rolled-in pricing distorts the communication of price signals, DOE also recognizes that this distortion is only a symptom of existing price controls. DOE believes that these distortions can only be fully eliminated by removing existing price controls on old gas.

The Department is concerned that the Commission's proposal would introduce into the economic evaluations [illegible] fuel and interruptible demand and establishing a [illegible] pricing structure for [illegible] customers. Under this proposal, no consumer would face a price that reflects a single [illegible] price for all gas.[33] Some [illegible] customers would pay [illegible] through their entitlements to [illegible] gas, while all other customers would pay the [illegible] price of [illegible]. As a result, efficient [illegible] customers would be encouraged to [illegible] gas.[34]

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[32] [illegible]

[33] [illegible]

[34] [illegible]

[illegible]

[illegible]

[illegible]

[illegible]

the current average price for gas.[25] These consumers would reduce their consumption in response to the higher price they paid for their marginal gas purchases. Producers would likewise reduce production in response to the lower prices they receive once the old gas cushion no longer supports the price of high-cost supplies.[26]

The net results of the Commission's proposal would be an economic gain by those firm-service consumers who received old gas entitlements, an economic loss by all other consumers, and an economic loss in aggregate for suppliers of imported and high-cost gas supplies. Producers that own only old gas supplies would not be affected by this proposal.

Concerns with the Proposed Billing Procedure. The Department is concerned with a number of risks that would arise in implementing the proposed billing procedure. DOE believes that there are serious questions whether the potential benefits of the billing proposal outweigh the risks associated with allocating an old gas entitlements to historical firm-service customers. Many gas customers could argue that the proposed base period for old gas billing would not fairly distribute entitlements to old gas purchasers, because some external event, such as warm weather or reduced economic activity, had altered their normal pattern of consumption. These customers would seek adjustments to their entitlements. This proposal would also alter the competitive balance between a company that operated during the base period and those that began operations after the base period.

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[25] Because old gas production is constrained, the price paid by consumers under current regulations reflects demand for new, imported, and high-cost gas at the average price of all gas. With the elimination of rolled-in pricing, consumers would face the same price as producers. Because this marginal price is higher than the current average price of all gas, consumer would reduce their demand for high-cost supplies. A new market-clearing price would emerge that is between the current average price of all gas and the current marginal price of high-cost gas.

[26] These price changes would result from increased economic pressures to renegotiate high-cost gas contracts. DOE does not believe that the Commission's proposal in any way invalidates existing contracts.

Further, the Commission's proposal may encourage pipelines to seek additional regulatory adjustments to "level the playing field" between pipelines. For example, a newer pipeline may argue that its assets should be depreciated at an accelerated rate to allow it to compete on an equal basis with an older pipeline. While DOE commends the Commission's efforts to increase competitive pressure, DOE does not believe the Commission intended to get into the business of equalizing "inequities" between pipelines.

DOE is also concerned that the effectiveness of the Commission's proposal would be reduced if distributors continue to roll-in the price of their old gas purchases with their other purchases. Distributors and state public utility commissions may treat old gas purchases in any of a number of ways. Because of this, the potential net benefits of this proposal may not be realized by consumers. For example, these benefits would be reduced to the extent that high-cost supplies continue to be subsidized by distributors.[27] This proposal may also create incentives for distributors to capture rents by expanding their rate base or by subsidizing rates of price-sensitive customers. A small but inefficient increase in distribution margins could easily capture the potential benefits of this proposal.[28]

Recovery of Incremental Supplies of Old Gas. Although recognizing the positive steps taken in the Commission's proposal, the Department notes that neither Congress nor the Commission has taken steps to eliminate the remaining economic distortions that result from price controls on old gas. These price controls constrain the production of low-cost old gas supplies, and result in the uneconomic production of more costly gas supplies. Old gas production is constrained under both existing regulations and under the Commission's proposal.

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[27] By transferring the old gas cushion from pipelines to distributors, the Commission could be creating incentives for distributors to bid up the price of their incremental purchases and roll-in these higher prices with the lower prices of their old gas entitlements.

[28] For example, an increase in distribution margins of only three cents per thousand cubic feet would increase annual revenues of distribution companies by about $270 million. From 1985 to 1995, this would result in additional distributor revenues of about $2.1 billion in real terms.

As a result, both policies fail to allow full recovery of about 38 trillion cubic feet of existing low-cost old gas supplies.[29]

The full loss of the 38 trillion cubic feet of incremental old gas production would result in net economic costs of about $26 billion (in constant 1982 dollars).[30] These costs result from lower overall production of natural gas at higher average prices than would occur if price controls were removed from all gas supplies. Lower production of gas at higher average prices would also increase the consumption of more expensive supplies of imported oil and gas.

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[29] Some may argue that the billing procedure would encourage partial recovery of these supplies by eliminating pipeline incentives to oppose higher prices for incremental production. Under current policy, pipelines must agree before producers are allowed to receive higher prices for production from new infill wells or from wells that have undergone production enhancement techniques. Because they no longer directly benefit from low prices for old gas, pipelines would have less incentive to "protect" the benefits of old gas by refusing to allow higher prices for incremental production. But, distributors would have strong incentives, as the new beneficiaries of old gas controls, to intervene in any cases before the Commission that allowed higher prices for incremental old gas production. In addition, there are a number of other obstacles to this production that are not removed by this proposal, including price ceilings, requirements for state approval, etc. These obstacles have prevented any significant incremental production under current regulation. Therefore, DOE believes that little or no incremental old gas production would result from adoption of the Commission's proposal.

[30] Under the comprehensive deregulation policy described in Increasing Competition, op. cit., net economic benefits totalled about $28.3 billion (p.143), of which about $2.3 billion are the result of the elimination of the natural gas surplus (p.99). Net economic benefits of the production of 38 tcf of incremental old gas supply therefore equal about $26 billion (in constant 1982 dollars).

DOE remains committed to fully removing existing price controls on natural gas supplies. Only the removal of price controls from all gas supplies will result in the elimination of all current gas market distortions and the full development of a competive and efficient market in which consumers receive adequate supplies of natural gas at reasonable prices.

Summary

The billing procedure proposed by the Commission takes positive steps to eliminate economic distortions that result from rolled-in pricing and the unequal distribution of old gas among pipelines. The Department estimates that consumers and the U.S. economy could realize net economic benefits of as much as $2.2 billion if the Commission's proposal is adopted.

The Department is concerned with a number of risks that arise in implementing this proposal. DOE believes that there are serious questions whether the potential benefits of the billing proposal outweigh the risks associated with allocating old gas entitlements to historical firm-service customers. DOE is also concerned that the effectiveness of the Commission's proposal would be reduced if distributors continue to roll-in the price of their old gas purchases with their other purchases. This proposal may also create incentives for distributors to capture rents by expanding their rate base. A small but inefficient increase in distribution margins could easily eliminate the benefits of this proposal.

Finally, the Department notes that this billing mechanism does not eliminate the major economic losses caused by price controls on old gas. The Department remains fully committed to decontrol of all natural gas prices.

Appendix A

CALCULATION OF NET BENEFITS OF ALTERNATIVE RATE DESIGN

DOE has utilized two aggregate, peak-load models to calculate the economic benefits of alternative rate designs for interstate natural gas pipelines. Benefits in both of these models are computed as the sum of producer and consumer surplus. The net present value in constant 1983 dollars of these benefits is calculated for a ten year period between 1985 and 1995.

The models differ, principally, in their assumptions about pipeline capacity. In the first model the capacity available for natural gas transportation is fixed. Because capacity is fixed, this model calculates the short-run economic effects of alternative rate designs. In the second model capacity is allowed to adjust with changes in consumption. Because these adjustments would occur over time, this model calculates the long-run economic effects of alternative rate designs.

A range of assumptions about transportation volumes are made for both models. The lower end of this range is 2 trillion cubic feet (tcf). This is currently the volume of gas being sold in the natural gas spot market. The high end of the range is 6 tcf. This includes pipeline exchanges and allows for reasonable increases in natural gas transportation as a result of the new transportation programs proposed in the NOPR.

The data used in these models are derived from several sources. Price and quantity data are taken from Two Market Model projections of wellhead and retail prices between 1985 and 1995 after being scaled down to represent assumed volumes of natural gas transportation. Fixed costs are determined from data in the 1983 EIA Statistics of Interstate Pipelines. Demand elasticities were derived from the midpoint of a range of estimates presented in a broad survey[1/] of demand elasticity studies.

Short Run Model

In the short run model, demand is assumed to have constant elasticity, and is distinguished by consumption sector and time of use. The two consumption sectors are industrial and residential/commercial. The different times of use are the peak and the off-peak periods. The peak period is January, February and December of each year while the off-peak period is the remainder of the year.

[1/] Bohi, Douglas, Resources for the Future, Price Elasticities of Demand for Energy: Evaluating the Estimates, prepared by the Electric Power Research Institute, Washington, D.C. September, 1982.

The two demand curves include one for firm-service demand and one for interruptible demand. Firm-service demand includes residential and commercial demand, as well as industrial demand during the peak period of gas deliveries. Both demand curves are assumed to have constant elasticity and are defined for each year of the model using the input elasticities derived for the peak load models, and input demand quantities (aggregate, old gas, domestic decontrolled gas, and imported gas), the computed volume weighted average price of all gas (i.e., the price paid by consumers under current regulation), and the price of old, domestic decontrolled, and imported gas taken from the base case projections of the Two Market Model for the years 1985 to 1995.

Consumer and producer surplus is calculated for each year in the model, as well as the net present value in constant 1983 dollars of the cumulative total of consumer and producer surplus. Case (1), current regulation, is used as the base case. Differences in welfare are calculated by subtracting the base case sum of consumer and producer surplus from the sum of consumer and producer surplus in each of the other two cases. The difference in welfare between cases is explained below:

Base Case vs. Billing Procedure.

In the base case, consumers pay an average price for decontrolled gas while decontrolled producers receive a higher

If volumetric rates are below prices that ration capacity, then excess demand for capacity exists during the peak period and a priority allocation rule is imposed. Under this rule, residential/commerical consumers obtain all the gas supplies they wish to purchase at the volumetric rate. Industrial consumers are constrained to take only those supplies that the remaining capacity can deliver. The economic benefits of peak volumetric rates as opposed to an annual volumetric rates range from $1.8 billion to $4.9 billion.

Long Run Model

The demand curves in this model are again assumed to have constant elasticity and are distinguished only by time of use. It is not useful to distinguish demand by consumption sector in this model since capacity is not constrained and priority allocation rules are not imposed. Pipeline capacity costs and marginal delivered gas costs are assumed to be constant.

This model computes the economic effects of two alternative rate design cases.

1. Peak Volumetric Rates

In this case, capacity is set where average capacity costs equals the time weighted average demand for capacity (between peak and off-peak periods). Peak period price is given by the height of the annualized peak demand curve at this capacity. Off-peak price is given by the marginal delivered gas cost.

2. Annual Volumetric Rates

In this case, peak and off-peak consumers pay the same price equal to average capacity costs plus the marginal delivered gas cost. Capacity is equal to annualized peak demand at this price.

The net economic benefits of using peak volumetric rate design range from $1.2 billion to $3.7 billion between 1985 and 1995 relative to volumetric rate designs, depending on interstate transportation volumes.

Appendix B

CALCULATION OF NET BENEFITS OF THE PROPOSED BILLING PROCEDURE

To calculate the net economic benefits of the proposed old gas billing procedure, DOE developed a simple static demand/supply equilibrium model of the interstate natural gas market. This model computes prices, quantities and welfare differences at the wellhead level of the domestic interstate natural gas market under three different policy cases. This model is limited to the interstate market to be consistent with the jurisdiction of the Commission over gas sales. The three policies examined include:

1. Current Regulation

Price ceilings on old gas are binding, constraining production of these supplies. All other gas receives a price that results in equal volumes of production and consumption, i.e. a price that clears the market. Producers of decontrolled gas receive the market-clearing price, producers of old gas receive the controlled price, and consumers pay a volume weighted average of the price of all gas.

2. Old Gas Billing Procedure

Firm-service consumers pay the controlled price for available quantities of old gas; old gas producers receive this price. Remaining demand for gas by firm-service and interruptible consumers is satisfied with new gas supplies at a price that clears the market. Both firm and interruptible consumers pay this price for all decontrolled gas they demand, decontrolled gas producers receive this price.

3. Old Gas Decontrol

All gas receives a market clearing price. Consumers pay this price, producers receive this price.

There are three supply curves and two demand curves in the model. The three supply curves include one for old gas, one for domestic decontrolled gas, and one for imported gas. All supply curves are assumed to have constant elasticity and are defined for each year of the model using input elasticities and input price/quantity pairs taken from the base case projections of the Two Market Model for the years 1985 to 1995.[1]

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[1] For a description of the Two Market Model, see Appendix D of Increasing Competition, op. cit.

The capacity available for transportation is determined as the appropriate fraction (depending on transportation volumes) of estimated total capacity. For the base case, prices in the off-peak period are set at marginal delivered gas cost. Prices in the peak period are set to ration capacity, that is, to insure that peak consumption just equals capacity.

Two different volumetric rate designs are considered: one based on an annual allocation of fixed costs to the peak period, the other based on an allocation of fixed costs to the peak period.[2/] In both cases the appropriate volumetric rate is determined by adding a per unit fixed charge to the marginal delivered gas costs. Volumetric rates based on an annual fixed cost allocation are equal for peak and off-peak consumers. The per unit fixed charge equals total fixed costs divided by total annual consumption. Under a peak volumetric rate design, rates during the off-peak period equal marginal delivered gas costs. Rates during the peak period equal marginal delivered gas costs plus per unit fixed charge -- i.e. total fixed costs divided by total peak consumption.

[2/] The former is assumed to represent current transportation rate designs while the latter represents the Commission's proposal. This in fact, places a downward bias on the estimated economic benefits of the Commission's proposal. Under current policies, the Commission credits transportation revenue to PGA Account 191. Additional economic benefits occur because this policy is eliminated.

marginal price that clears the market when rolled in with old gas prices. The gap between the current average price and the higher marginal price of decontrolled gas is the result of averaging in old gas quantities to determine consumer prices. In the billing case, consumers pay a new, lower marginal price for decontrolled gas and consume a new, lower quantity of this gas, while producers receive the same lower marginal price for the quantity of gas demanded by consumers.

The new price consumers pay for decontrolled gas is between the current average price of all gas and the current marginal price for decontrolled gas. This occurs for the following reason. Once consumers pay the same price that producers receive, consumers are faced with three choices, to either (a) pay a higher price for volumes they were receiving at a lower price, or (b) pay the same price for smaller volumes, or (c) choose new levels of demand below current levels, and pay a price above the current average price for all supplies and below the current marginal price for decontrolled supplies. Consumers will choose (c). This choice determines a new marginal price for decontrolled supplies that is received by producers and paid both by interruptible consumers and firm consumers with demand not satisfied by the constrained supply of old gas.

Because this price is above the current average price, these consumers suffer a loss of consumer surplus (higher price, reduced volumes). For decontrolled gas producers, the new marginal price of decontrolled gas is less than the current marginal price of decontrolled gas. Therefore, producers suffer a loss of producer surplus (lower price, reduced volumes). Old gas producers receive the same price and produce the same quantities. Entitled firm consumers realize a gain in consumer surplus. This gain is largely a transfer of the approximately equal net losses of producers and interruptible consumers. Entitled firm consumers pay a controlled price that is below the current average price. The net of these gains and losses is the change in social welfare that occurs by moving from current policy to the billing procedure.

Base Case vs. Decontrol Case

In the decontrol case, producers and consumers both see one price, the true market-clearing price of gas. Old gas production is no longer constrained and production of old gas increases, displacing high-cost gas production. The true market-clearing price for all gas is above current old gas prices and below current decontrolled gas prices received by producers at the margin. Old gas producers therefore realize a gain in producer surplus, because they receive a higher price and produce greater quantities. Current decontrolled gas producers suffer a loss of producer surplus, because they receive a lower price and produce smaller quantities.

The true market-clearing price of all gas is also below the current average price paid by consumers. The current surplus of deliverable production is evidence of this. Therefore all consumers realize a gain in consumer surplus, because they pay a lower price and consume greater quantities. The net of producers and consumers surplus represents the change in social welfare by moving from current regulation to the decontrol of all gas supplies.

This model underestimates the net economic benefits of decontrol relative to the calculations that are obtained from the Two Market Model for two reasons. First, the Two Market Model calculates benefits that result from reduced payments for all energy consumption, while this model only calculates benefits that result from reduced payments for gas consumption. Second, this model only includes data for interstate pipelines. Because this reduces the total volumes that are allowed to be affected by a change in policy, net economic benefits are underestimated.

Senator Nickles. Mr. O'Connor, could you explain in your opinion what the benefits to consumers and producers would be of the Commission's notice of proposed rulemaking?

Mr. O'Connor. Well, we think there's going to be several to both of those categories. I think on an overall basis relative to consumers, we hope that the notice of proposed rulemaking and the proposals encompassed therein secure for consumers the benefits of competition in natural gas markets consistent with the NGPA and the NGA, which I mentioned in my statement.

As far as local distribution companies and end users are concerned, they would have access if the certificate would be accepted by the pipeline, the open-access certificate. They would have nondiscriminatory access to transportation if the pipeline held itself out as a transporter.

Third, the customers of the pipelines under the proposal have conversion rights, rights to reduce their firm purchase entitlements to transportation, which should be of benefit to consumers.

The reserved entitlements to old gas should be of benefit to the consumers, and the forever-regulated gas under the two-block billing proposal in the rulemaking, that forever-regulated gas is reserved to the historical customers of the pipeline based on 3-year takes for the past 3 years.

The billing procedure also would transmit accurate price signals, or should, to new customers so that the cost of supplies should be accurately reflected to new customers of the pipeline; and the optional expedited certificate procedure would create incentives for local distribution companies and thereby hopefully benefit their customers—incentives for more efficient purchasing practices. And, under the expedited procedure, no costs could be shifted to the other customers.

On your question relative to producers——

Senator Nickles. Before you move to producers——

Mr. O'Connor. Sure.

Senator Nickles. For consumers, would it be fair to say that it'd be your intent, or your thought, or your expectation that lower prices would ensue as a result of the rulemaking?

Mr. O'Connor. I think, based on the comprehensive nature of the rulemaking, if finalized as proposed—and of course all this is subject to the comments that we'll be receiving—that would be our expectation, yes.

Senator Nickles. That consumers would get a price break?

Mr. O'Connor. That prices would be market-responsive, and therefore under the current surplus deliverability situation, prices to the ultimate consumer should be lower than they are today, yes.

Senator Nickles. Mr. Chairman, as you know there's a great deal of shut-in gas throughout the country in my State of Oklahoma, as well as in New Mexico, Louisiana, and Texas. How will the Commission's NOPR help the marketability of natural gas, particularly gas that's now shut in and can't find a market?

Mr. O'Connor. Well, I think the proposed rule would help the shut-in gas situation in probably two or three ways. One is access. There's nondiscriminatory access to the pipelines, and therefore there is a way to market gas. The buyout procedure, if implemented between the pipelines and producers, will help extinguish or do away with the problem contracts, and under the billing procedure there should be more accurate and clear price signals between the marketplace and the producers.

With the open access—which we've heard many, many times over and over through the 5 months of the notices of inquiry—the producing segment consistently stressed the nonaccessibility to the pipeline network as the major problem. So I think the shut-in producers would have that access more available if in fact the pipeline picks up a conditional certificate.

I think over and above that, on abandonment we have two producer abandonment cases which we have just recently, in the last few weeks, set for hearing, where the pipeline was not taking a sufficient amount of gas for economic production. Both of those cases have been set for hearing, and we will be looking into abandonment based on the public interest requirement of section 7(b) of the Natural Gas Act.

In addition to that, we have recognized that under the proposed rule there may need to be changes in the procedures for abandonment. So we have asked for comment in the proposed rule for exactly what procedural changes to producer abandonment may be required, and we will be receiving comments on that question.

Senator NICKLES. If the Commission's NOPR is implemented as proposed, would that, in your opinion, elminate the need for mandatory contract carriage?

Mr. O'CONNOR. If the pipelines totally accept the conditioned certificate, transport for one and transport for all, if there is total acceptance on behalf of the pipelines, it would seem that there would then be a total open access to the national transportation system. I would think that would be sufficient to carry out the national transportation strategy or the objectives of the NGPA, and therefore there would be the ability to move gas throughout the United States.

I guess that would say that probably regarding mandatory carriage—it would be equivalent really to the carriage.

Senator NICKLES. Mr. Chairman, one final thing. You mentioned in your part B the take-or-pay relief.

Mr. O'CONNOR. Yes, sir.

Senator NICKLES. You mentioned that for a certain transition period at the option of the pipelines and the suppliers, a rebuttable presumption of prudence would be established?

Mr. O'CONNOR. Yes, sir.

Senator NICKLES. Would you explain that a little more?

Mr. O'CONNOR. Well, under the proposal, during the 4-year transition period, there would be, per year, 25 percent of the customers' contract entitlements available to be shifted to firm transportation arrangements. I think the rationale for that is that we heard again over and over in the NOI procedures that some transition period should be required.

Relative to large distribution companies with multiple suppliers and flexible options, this may not be of crucial importance. It is of crucial importance to the small, smaller distribution companies that are supplied by a single pipeline. In particular for many municipal gas systems around the country, the 4-year period, 25-percent-per-year switch to transportation is particularly crucial. Those smaller entities will require this particular transition.

The rebuttable presumption would be applicable after the 4-year period and after the acceptance, of course, of the conditioned certificate for the open access, thereby creating in effect competition between sales and transportation. So the monopoly over sales will no longer be in existence because there is this opportunity for customers to shift their contract demand from firm sales to firm transportation.

Senator **Nickles**. Thank you, Mr. Chairman.

For the questions, I think we'll go by order of appearance. Senator Ford.

Senator **Ford**. Senator Warner was here before I was.

Senator **Nickles**. Senator Warner, excuse me.

Senator **Warner**. I thank the Senator from Kentucky. I've already had one question. I'll press on with one other. That is: Mr. Boggs, as the administration develops its position I would hope that would embrace a position on the Fuel Use Act. Can you opine now as to what that might be with respect to the Fuel Use Act? I say this, because we received news here in the past few days about the balance of payments of this country, and indeed to the lesser extent we're dependent on foreign oil that would be improving the balance of payments, and that would out that the more we could use gas, the less foreign oil.

Mr. **Boggs**. Senator, I would certainly imagine that we would take a position on that. In the administration's legislation in the past session we indicated that we believed that the Fuel Use Act was not appropriate. Certainly to the extent that it has any effect, it is to block natural gas out of certain markets in which it might displace at the margin foreign oil and that displacement is in general one of the emphases of our energy policy.

As I say, I think we'll have to look at the overall context of all of the bills before us, but we have in the past supported repeal, and we have not been——

Senator **Warner**. So you would anticipate a consistency of that position?

Mr. **Boggs**. I would anticipate that.

Senator **Warner**. Thank you.

Thank you, Mr. Chairman.

Senator **Ford**. You're the chairman.

Senator **Warner** [presiding]. I'm suddenly elected. I'll defer to you.

Senator **Ford**. Thank you, sir.

Let me follow up with Mr. Boggs just a minute. What is the price of old gas? You gave us $2.81 as the price of new gas for January and February of this year. What's old gas?

Mr. **Boggs**. Well, old gas comes in a number of types. I think the last average of all types of old gas I saw was about $1.45, but I'd like to supply that for the record, because that's just off the top of my head.

[The information follows:]

Industry Overview

Table 22. Projected Volumes and Prices of Wellhead Purchases by NGPA Category
(Volumes in Billion Cubic Feet, Prices in Dollars Per Thousand Cubic Feet)

	Section 104[a]		Section 105[b]		Section 106[c]		Old Gas[d]	
	Volume	Price[e]	Volume	Price[e]	Volume	Price[e]	Volume	Price[e]
1981 Total	5,271	1.22	46	2.56	237	1.00	5,553	1.22
1982 Total	5,311	1.34	48	2.63	285	1.08	5,644	1.34
1983								
January	388	1.40	5	2.77	24	1.08	416	1.39
February	380	1.40	5	2.79	23	1.08	409	1.40
March	387	1.43	5	2.87	25	1.08	417	1.42
April	369	1.45	5	2.81	25	1.08	398	1.44
May	343	1.43	5	2.81	23	1.09	370	1.42
June	343	1.43	5	2.81	23	1.09	370	1.42
July	335	1.40	4	2.57	20	1.08	358	1.40
August	331	1.41	4	2.56	20	1.09	354	1.40
September	301	1.35	4	2.51	18	1.10	323	1.35
October	310	1.34	4	2.65	18	1.11	332	1.34
November	330	1.37	4	2.65	19	1.11	353	1.38
December	330	1.37	4	2.65	19	1.11	353	1.38
Total	4,146	1.40	52	2.72	255	1.09	4,453	1.40
1984								
January	358	1.42	4	2.57	21	1.11	383	1.41
February	358	1.44	4	2.62	22	1.11	384	1.43
March	348	1.45	5	2.50	22	1.11	375	1.45
April	339	1.46	5	2.57	21	1.13	365	1.46
May	318	1.43	5	2.57	21	1.12	345	1.43
June	318	1.43	5	2.57	21	1.12	345	1.43
July	R322	1.45	5	2.54	21	1.13	R349	R1.45
August	R320	1.44	5	R2.61	R22	R1.12	R347	1.44
September	R307	R1.47	3	R3.18	R22	R1.12	R332	R1.46
October	R319	R1.50	3	R3.18	R27	R1.13	R349	R1.49
November	R347	R1.60	3	R3.18	28	R1.14	R378	R1.58
December	R347	R1.60	3	R3.19	28	R1.14	R378	R1.58
Total	R4,003	R1.48	50	R2.71	R277	1.13	R4,330	R1.47
1985								
January	R323	R1.65	3	R3.13	27	R1.14	R353	R1.62
February	R327	R1.64	3	R3.07	27	R1.14	R358	R1.61
March	R307	R1.59	3	R3.11	R27	1.15	R337	R1.57
April	R295	R1.62	R4	R2.77	R29	R1.14	R329	R1.59
May	285	1.55	4	2.77	30	1.14	320	1.53

See footnotes at end of table.

Senator FORD. We're talking about energy here, and the distinguished Senator from Virginia talked about the reduction of imported oil. Are you familiar with OPEC's meeting having been scheduled for July is now scheduled for the last of June? They moved it up a month.

Mr. BOGGS. They moved it up a month, and then I think they moved it back a week, and it's in that timeframe.

Senator FORD. My information indicates that basically all OPEC countries are cheating on price based on the announcement at their last meeting. What do you think the price of oil will be from the next OPEC meeting? Have you got a judgment?

Mr. BOGGS. No, sir.

Senator FORD. You don't have any judgment? You don't think it'll be $20 a barrel?

Mr. BOGGS. I would be surprised if it were.

Senator FORD. Do ya'll follow those sort of things as it relates to energy?

Mr. BOGGS. Yes.

Senator FORD. You don't have any judgment? [Laughter.]

Mr. BOGGS. We follow it quite closely. The question of how much better our judgment is than the next fellow's is always questionable.

Senator FORD. Well, but it's your job to give us those estimates. We can prove you wrong, though. [Laughter.]

Mr. BOGGS. Well, one of the things we've tried to put into energy policy is to say that just because the Government gives you a figure doesn't mean that everybody ought to believe it. [Laughter.]

I think in the past we've gotten into trouble both by the Government trying to overstate its certainty, and by others overstating its credibility. I've indicated in the past that it appears to me that the likely trend of pressure on real-world oil prices is going to be downward. Of course in effect the spot market and the futures' markets are already significantly below the OPEC official prices. Whether those markets—whether those spot and futures' markets—are going to go significantly lower than they are now is quite problemmatical. I notice this morning the futures price for a year from now is $24 a barrel. Whether it's going to go significantly below that I think is quite a difficult question.

Senator FORD. Mr. O'Connor, let me get down to the nitty gritty with you. The notice of proposed rulemaking discussed in your testimony represents what we've referred to and what you've referred to as a comprehensive approach to the natural gas transportation policy.

Now let me ask you this: Do you believe you have sufficient legal authority to implement the proposed rulemaking, especially in the light of the recent decision by the court of appeals invalidating your Blanket Certificate Program?

Mr. O'CONNOR. Regarding your first question, we do believe that we have legal authority. We have asked for comments in that regard in several areas.

Senator FORD. Comments for what, now?

Mr. O'CONNOR. On the legal—for instance, on the two-block billing procedure; comments relative to the legal authority under the statute to do that. We believe we have legal authority to implement the rule as proposed.

Relative to the second part of your question, concerning the court of appeals' case, part of the notice of proposed rulemaking is consistent with basically what the court in the blanket certificate case has said. Namely, open access for the so-called captive customers is available or would be available if the proposed rule is finalized.

Senator FORD. Well, were you constrained at all in proposing what you believe is an appropriate transportation policy by concern of having lack of statutory authority?

Mr. O'CONNOR. No; we were not—we did not feel overly constrained. We think the proposed rule——

Senator FORD. You're not overly constrained? But you were concerned, then?

Mr. O'CONNOR. There are some questions in the proposed rule which we're asking for comments on.

Senator FORD. Well, I understand that, but I'm asking about your legal authority. Comments would be from the general public; isn't that correct? And then you would hold a hearing?

Mr. O'CONNOR. That's correct.

Senator FORD. I'm back prior to that. If I understood you correctly, you were not—you were concerned about it, but not constrained.

Mr. O'CONNOR. We were concerned to the extent that certainly this notice of proposed rulemaking has been drafted and has been reviewed thoroughly by our Office of General Counsel, and they looked at all the possibilities of where any problems might arise. And under the Natural Gas Act, sections 4, 5, 7, and 16, and under the NGPA and under the DOE Organization Act, the general counsel's office had concluded that the notice of proposed rulemaking was legally sufficient in their opinion to be issued by the Commission.

Senator FORD. Well, then, you don't believe any new statutory authority is necessary in order for the Commission to implement the policies necessary to ensure the so-called long-term health of this Nation's natural gas industry?

Mr. O'CONNOR. We are not asking for any statutory authority.

Senator FORD. You don't need any?

Mr. O'CONNOR. No; we do not.

Senator FORD. Your notice of proposed rulemaking seeks to protect existing natural gas customers of old gas supplies. Your testimony on page 21, I believe, states that, and I quote, "This proposed rule is intended to provide customers with a clearer understanding of the mix of gas being offered by the pipeline and of the real cost of incremental consumption. At the same time, the proposal would not change the total gas bill charged to current customers assuming their current purchased volumes remain the same."

Mr. O'CONNOR. Yes, sir.

Senator FORD. I don't understand, Mr. Chairman, why bills paid by current gas customers would not go down if old gas supplies are saved for existing customers. Would——

Mr. O'CONNOR. Well, the important—excuse me—the important part of that quotation is, "assuming that the volumes remain the same." The two-block procedure merely is a billing mechanism separating out the cost of the old gas and the new gas. The old gas and the new gas, the block 1 and the block 2, will be billed on a rolled-in basis within those two blocks.

So assuming that the volumes purchased remain the same, the block 1 rolled-in price added to the block 2 rolled-in price will equal the same amount of the bill presently being paid, assuming the volumes remain the same.

Senator FORD. Does that mean that the pipelines still receive the average cost?

Mr. O'CONNOR. No; because of the billing mechanism, the pipeline will bill the old gas and the new gas——

Senator FORD. Separately?

Mr. O'CONNOR [continuing]. Separately. That's all. This is merely, and I——

Senator FORD. They wouldn't have an opportunity to just average it and send the bill?

Mr. O'CONNOR. They would not have the opportunity to do what they do today, averaging all of the gas into one bill.

Senator FORD. That sounds like a plumber charging you $20 an hour and 5 cents for a washer.

Mr. O'CONNOR. Well, but you can find out what the price of the washer is. Today, for incremental supplies the pipeline markets can't tell what that price is because they are seeing at the market end a rolled-in price.

Senator FORD. Let me ask you the question again, if I can. Wouldn't existing customers bills go down if rates are designed to provide them with the benefit of a pipeline's old gas supplies?

Mr. O'CONNOR. I'm sorry? Could you repeat that, please?

Senator FORD. Wouldn't existing customers bills go down if rates are designed to provide them with the benefit of a pipeline's old gas supplies?

Mr. O'CONNOR. We're talking about other than the billing mechanism, because under the billing mechanism itself, there would be no change assuming the same volumes remain the same.

Under the overall proposal, because of these more accurate price signals and because of the buy-out procedure and because of the ability to use the mechanism to buy out problem contracts, looking at the whole comprehensive nature of the package, we would expect that the prices would be market-responsive, and in a surplus prices would go down.

But looking at the billing mechanism in and of itself, it is purely a mechanism to roll in the old gas, bill it separately, roll in the new gas, bill it separately, and thereby create the mechanism for price signals accurately being transmitted between the wellhead and the marketplace.

Senator FORD. You call this simplification of billing, by doing it this way?

Mr. O'CONNOR. If you just look at the billing mechanism in and of itself, yes. But the consequences of that more simplified billing and the reservation of the old gas to the historical customers and the new gas for new customers, is a powerful pricing signal mechanism for both the producing end of the industry as well as the marketplace. Where there's been increasing competition at both ends, the transmittal of accurate price signals is essential for the efficient operation of the market. With the pipeline still in between and with the conditioned open access, we feel that the national movement of gas will take place.

Senator FORD. Let's see if we can simplify your answers a little bit. I don't really know where you started when I get to the end of your answer. [Laughter.]

I apologize for not being able to follow you, but I'm having a hard time even keeping my checkbook balanced, let alone understand what you're doing.

What is the Commission's position, then, on the bypass of a local distribution company by industrial end users and/or pipelines competing to serve those end users directly?

Mr. O'CONNOR. Well, currently—I'll try to be more simple and less wordy—but currently the situation is that there is a great impetus for the industrial users to bypass. The reason is that there is cheaper gas able to be bought in the field, and the industrial user is not seeing the value of that gas because of the rolled-in pricing, which gets us back into the billing mechanism.

So there's a great incentive for bypass. Under the notice of proposed rulemaking, we feel that the incentive will be far less. The reason is, one, that there will be price signals accurately transmitted; and, two, there is through the threat of competition for the LDC under the optional expedited certification procedure. There is a real incentive for the local distribution companies to have more efficient purchasing practices, and to have lower prices to these industrial end users.

We heard over and over during the notice of inquiry that the industrial users are not all that interested in going out and buying in the field. They would prefer to deal with their local distribution company. But if they could buy cheaper gas out in the field themselves, there is the incentive for the bypass.

Senator FORD. Well, then, the Commission itself does not have a position on bypass. The only thing you just said to me in that statement was, this would encourage them not to bypass.

Mr. O'CONNOR. We do not have a position on bypass. We don't have any cases before us on bypass. We have one pending that is not—the Commission has not decided. But the bypass issue illustrates the comprehensive nature of the NOPR. The integrated, interrelated nature of this procedure proposed by the Commission really comes to the fore, in my opinion, when you're talking about the bypass issue. The four parts of it really are interrelated, and they seem to come together with that particular issue.

Senator FORD. You are basically interested in the cost of the gas to the consumer? Am I correct in that statement?

Mr. O'CONNOR. Yes, sir.

Senator FORD. All right. Then how does the Commission's proposed rule impact this bypass issue, particularly in light of the fact that a bypass increases the amount of fixed cost paid by residential consumers of the local distribution company?

Mr. O'CONNOR. Well, in the proposed rule on the optional certificate procedure, if a pipeline, or if a second supplier wants to in effect bypass the present supplier to that industrial customer, one, he's at risk if he wants to do that because it's a new service. The impact on the LDC because of the threat of that competition should be, and because of the market sales price more accurately reflecting cost through the billing procedure, the incentive to the local distribution company in that situation should be to be more efficient; therefore bypass we think will be lessened, and if in fact the industrial company does hook up to a second supplier, one, if that project fails, under this proposal the pipeline is at risk and the pipeline is not permitted to pass those costs on or to shift costs to any other customers.

So again, the comprehensive, interrelated nature of this package we think creates various incentives to all the parties to be more efficient and prices should be lower.

Senator FORD. What costs are included in block 3 of the proposed purchased gas billing procedure?

Mr. O'CONNOR. The block 3 costs are more miscellaneous costs of gathering and loss of—fuel loss, and we are asking for comments in the proposed rule on how those No. 3 block costs should be allocated between the blocks—blocks 1 and 2. But they're basically nongas costs.

Senator FORD. Nongas costs?

Mr. O'CONNOR. Nongas costs.

Senator FORD. Well, let's take a hypothetical case, then. When an interstate pipeline buys gas from another interstate pipeline, pipelines block 1, are these costs allocated to the purchaser's pipeline block 1, 2, or 3?

Mr. O'CONNOR. Well, the block 1 costs from the selling pipeline would be block 1 PGA cost for the purchasing pipeline.

Senator FORD. None of it, then, is allocated as miscellaneous, or cost of purchase, or anything like that that would go in block 3?

Mr. O'CONNOR. The intention of block 1 would be purely to have those gas costs in block 1, and the Commission has not determined—if at all—how to allocate those block 3 costs. We are asking—we have asked for comments on that specific question.

Senator FORD. You've got block 3, but you really don't know what to do with it?

Mr. O'CONNOR. At this particular point in time——

Senator FORD. Why did you put block 3 in?

Mr. O'CONNOR. Just to separate out the nongas costs.

Senator FORD. Just to separate it out.

Mr. Chairman, I have several other questions for Mr. O'Connor, and I would like to submit those to him in writing. If you get those today, Mr. O'Connor, when could I expect them back for the committee?

Mr. O'CONNOR. When would you like them? [Laughter.]

Senator FORD. Well, when could you get them here? You know, I'm at your disposal. If you can't get them here, I can't get them.

Mr. O'CONNOR. Well, we can get them to you as quickly as you want them.

Senator FORD. Are you going to have them by the end of the week?

Mr. O'CONNOR. Sure.

Senator FORD. All right——

Mr. O'CONNOR. Depending—now I don't know what the questions are. [Laughter.]

I'm making that offer in the blind.

Senator **Ford**. Mr. O'Connor, let me just do this. Could I have them next week before we leave on the 28th?

Mr. **O'Connor**. Sure.

Senator **Ford**. Could I have them by the 27th? I promise you they'll just be simple, easy questions.

Mr. **O'Connor**. You're not going to have 185 questions?

Senator **Ford**. No; it probably will be about 10. And also, Mr. Chairman, Senator Rockefeller is unable to be here because he's testifying on the House side. He'd also like the opportunity to submit the questions to Mr. O'Connor for the record.

Mr. **O'Connor**. We will surely do that.[1]

Senator **Ford**. Thank you, sir.

Senator **Nickles** [presiding]. Senator Ford, I compliment you. It only took FERC about 10 or 12 years to decide on the *Williams* case, and you're getting decisions in a week. You're doing real well. [Laughter.]

Senator **Ford**. Well, that's anticipated, and we assume they'll be here. Now you begin to get into all that, and we'll find out how good it is.

Senator **Nickles**. Senator Bingaman.

Senator **Bingaman**. Thank you, Mr. Chairman. I also have a few questions I'll submit for a written response, if I could, Mr. O'Connor.

Mr. **O'Connor**. Sure.

Senator **Bingaman**. I appreciate that.

Let me ask you, Mr. Boggs, just a question or two about Canadian gas. Maybe you could bring me up to date on what the extent of the imports of Canadian gas are, what percent of the markets they account for at this time, and what your understanding is as to the relative pricing of the Canadian gas versus our own gas.

I think you refer to that some in your testimony, but I would like a little elaboration, if possible.

Mr. **Boggs**. OK. This is, as I say, off the top of my head, and I will provide specific numbers in the record. But basically, imports of foreign gas, which are overwhelmingly Canadian, have been in the vicinity of 4 or 5 percent of the total United States market say for the last 10 years.

There was a peak about 1979 when we were also getting a good bit of Algerian LNG supplies. The last figures that I saw, which I think are through 4 months of 1985, is that imports from Canada are running a little bit ahead of last year. If they continued at that pace, they would be well below the average of the last 10 years, but higher than last year and maybe 1 or 2 other recent years.

[The information follows:]

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[1] See appendix I.

Table G6. Historical Summary of Natural Gas Exports, 1955-1984 (Volume in Million Cubic Feet; Average Price in Dollars per Thousand Cubic Feet)

Year	Exports to Canada Pipeline	Exports to Mexico Pipeline	Exports to Japan LNG	Total Exports[a]	Average Price
1955	11,494	19,903	0	31,397	NA
1956	17,164	19,499	0	36,663	NA
1957	25,368	14,998	0	40,366	NA
1958	32,128	10,790	0	42,918	NA
1959	11,740	10,794	0	22,534	NA
1960	5,574	10,526	0	16,100	NA
1961	5,578	9,638	0	15,216	NA
1962	5,575	10,255	0	15,830	NA
1963	6,880	10,068	0	16,948	NA
1964	9,654	9,842	0	19,496	NA
1965	17,892	9,536	0	27,428	NA
1966	44,958	9,902	0	54,860	NA
1967	70,456	11,139	0	81,595	NA
1968	81,647	12,098	0	[b]93,745	NA
1969	34,936	13,390	[b]2,982	[b]51,308	NA
1970	10,860	14,678	[b]44,257	[b]69,795	NA
1971	14,349	15,785	[b]50,231	[b]80,365	NA
1972	15,553	14,579	47,882	78,013	0.51
1973	14,824	13,999	48,346	77,169	0.54
1974	13,263	13,268	50,258	76,789	0.72
1975	10,219	9,454	53,002	72,675	1.25
1976	7,506	7,425	49,779	64,710	1.55
1977	31	3,940	51,655	55,625	1.92
1978	66	4,033	48,434	52,532	2.13
1979	76	4,308	51,289	55,673	2.29
1980	113	3,886	44,732	48,731	4.70
1981	106	3,337	55,929	59,372	5.90
1982	162	1,705	49,861	51,728	5.81
1983	136	R1,646	52,857	R54,639	5.10
1984	127	1,786	52,840	54,753	4.92

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[a] Volumes reported for 1966 and later are on a pressure base of 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Volumes for 1965 and before are as reported. Pipeline data before 1972, the first year for which Form FPC-14 was used, were obtained informally by the former Federal Power Commission. Data for exports of LNG to Japan, for years 1969 through 1971, were obtained from the Bureau of Mines, U.S. Department of Interior, Natural Gas Production and Consumption.

[b] Data on LNG exports to Japan were not previously reported in this publication for years 1969 through 1971

NA = Not available.

R = Revised

Note: Totals may not equal sum of components due to independent rounding.

U.S. Natural Gas Net Imports and Total Natural Gas Consumption, 1972-1984

Year	Total Consumption[a] billion cubic feet	Gross Imports billion cubic feet	Exports billion cubic feet	Net Imports billion cubic feet	Net Imports as Percentage of Total Consumption
1972	22,101	1,019	78	941	4.3
1973	22,049	1,033	77	956	4.3
1974	21,223	959	77	882	4.2
1975	19,538	953	73	880	4.5
1976	19,946	964	65	899	4.5
1977	19,521	1,011	56	955	4.9
1978	19,627	966	53	913	4.7
1979	20,241	1,253	56	1,198	5.9
1980	19,877	985	49	936	4.7
1981	19,404	904	59	845	4.4
1982	18,001	933	52	882	4.9
1983	16,835	918	55	864	5.1
1984	[b] 17,485	843	55	788	4.5

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[a] Natural Gas Production and Consumption 1976 [2] for 1972; Natural Gas Annual 1983 [3] for 1973 through 1983; Natural Gas Monthly May 1985 for 1984.

[b] Preliminary.

Note: Totals may not equal sum of components due to independent rounding.

Mr. Boggs. But the whole swing in what we're getting now would be an the increase on the order of one-half percent, or 1 percent of the total U.S. market. The price of those supplies, based on a couple of different measures, would be about where U.S. new gas, section 102 gas prices are, give or take a little bit. They might be a little bit higher. I've seen average numbers in the low $3 range whereas, total U.S. wellhead is about in the $2.50 to $2.60 range. But of course the new gas would be getting a higher price and the old gas a lower price.

So those are the rough parameters, and I'll supply exact numbers for the record.

[The information follows:]

Historical Summary of Natural Gas Imports, 1955-1984
(Volume in Million Cubic Feet; Average Price in Dollars per Thousand Cubic Feet)

Year	Imports from Canada Pipeline	Imports from Canada LNG	Imports from Mexico Pipeline	Imports from Algeria LNG	Total Imports[a]	Average Price
1955	10,885	0	7	0	10,892	NA
1956	10,586	0	6	0	10,592	NA
1957	21,060	0	16,970	0	38,030	NA
1958	88,230	0	46,211	0	134,441	NA
1959	81,892	0	50,929	0	132,821	NA
1960	109,855	0	46,988	0	156,843	NA
1961	168,822	0	51,755	0	220,577	NA
1962	342,770	0	51,066	0	393,836	NA
1963	357,961	0	49,762	0	407,723	NA
1964	392,239	0	52,620	0	444,859	NA
1965	404,687	0	52,007	0	456,694	NA
1966	431,855	0	48,636	0	480,491	NA
1967	513,256	0	50,972	0	564,228	NA
1968	604,462	0	47,423	[b]100	[b]651,985	NA
1969	680,107	0	46,845	[b]94	[b]727,046	NA
1970	778,688	[b]56	41,336	[b]757	[b]820,837	NA
1971	910,925	[b]1,500	20,690	[b]1,433	[b]934,548	NA
1972	1,009,093	230	8,140	2,032	1,019,495	0.31
1973	1,027,216	667	1,632	3,388	1,032,903	0.35
1974	959,063	0	222	0	959,285	0.55
1975	948,115	0	0	4,893	953,008	1.21
1976	953,613	0	0	10,155	963,768	1.72
1977	996,723	572	2,384	11,324	1,011,002	1.98
1978	881,123	0	0	84,422	965,545	2.13
1979	1,000,775	0	0	252,608	1,253,383	2.49
1980	796,507	0	102,410	85,850	984,767	4.28
1981	762,107	6	105,013	36,824	903,949	4.88
1982	783,407	0	94,794	55,136	933,336	5.03
1983	711,923	0	75,361	131,124	918,407	4.78
1984	755,368	0	51,502	36,191	843,060	4.08

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[a] Volumes reported for 1966 and later are on a pressure base of 14.73 pounds per square inch absolute and 60 degrees Fahrenheit. Volumes for 1965 and before are as reported. Pipeline data before 1972, the first year for which Form FPC-14 was used, were obtained informally by the former Federal Power Commission. Data for imports of LNG from Algeria and Canada, for years 1968 through 1971, were obtained from the Bureau of Mines, U.S. Department of Interior, *Natural Gas Production and Consumption*, and from Boston Gas Company, Boston, Massachusetts (the first U.S. recipient of LNG from Algeria and Canada).

[b] Data on LNG imports from Algeria and Canada were not previously reported in this publication for years 1968 through 1971.

NA = Not available.

Note: Totals may not equal sum of components due to independent rounding.

Senator **Bingaman**. Let me be just a little more specific. My impression is that there have been a significant number of gas wells shut in in the Southwest in my home State of New Mexico, as an example, because of Canadian gas coming in to the California market with a cheaper, or at really a more expensive price than the gas was available for through the Southwest.

Now maybe that situation has changed. That's 6 months' or 1 year old, that information of mine, but do you know anything about that? My information was that the Canadian gas was coming in at about $4.40 an Mft^3, and the gas was available in the Southwest at a cheaper price for delivery to the California market.

Mr. **Boggs**. I'm generally familiar with the fact that there was a controversy at that time. It's also the case that most Canadian gas has come down in price significantly in the last 6 months to 1 year. I'm not immediately familiar with why people would buy gas at a higher price if gas at a lower price were available.

Now some of the regulatory aspects, both interstate and intrastate, might affect that. If there is a specific pipeline or a specific purchaser, I'd be happy to try to look into it. I am aware of a general controversy about competition from Canadian gas, and of course as Chairman O'Connor and our testimony indicated, there's a fair amount of gas shut in around the country for a number of reasons, but primarily turning on the inability to get that gas transported to a market.

Senator **Bingaman**. Just to summarize, then, you don't see the importation of natural gas from Canada as in any way something that would require any response by us or any kind of additional regulatory concern on our part?

Mr. **Boggs**. Well, we have certainly been responding to the importation of Canadian gas over the last several years by trying to get Canada to move toward a market pricing system in which we have been quite effective. In terms of that importation being something that we should attempt to restrict, or bar, or place tariffs on, certainly under current circumstances—and I think the foreseeable circumstances—the answer is no.

That may well be another reason that we need to take measures to free up the transportation system so that even if there is competition, people who lose out for a particular bid or a particular deal can still get their gas transported to other markets; but in terms of the United States wanting to restrict those imports, that would not be our position.

Senator **Bingaman**. That's all I had, Mr. Chairman. Thank you very much.

Senator **Nickles**. Thank you, Senator.

Senator Evans.

Senator **Evans**. Let me just continue the questioning along the Canadian lines since we in the Northwest get a good deal of our gas currently from Canada or through Canada. Would either or both of you care to just comment in general? The policies that you are advocating and the direction you would like to see the Government take in terms of its regulatory attitude toward natural gas in this country, in your view what impact if any will that have on Canadian pricing policies, availability of Canadian gas, or the relationship of what we do with them?

Mr. BOGGS. Well, let me speak in the broad context, and then perhaps Chairman O'Connor could speak about the FERC regulations. As you know, for many years Canadian gas was much higher priced than alternative supplies because they were filling a gap which we had created by our regulatory policy.

Over the past several years as we have moved toward a freer market, that competition has meant that Canada has had to reduce its prices in order to remain competitive. And with the new Government in Canada, that process is coming to a completion.

To the extent that the American market is competitive, that more supplies are available, that American prices remain under pressure, those Canadian supplies will have to match it in order to stay in the market. So that to the extent that both we and Canada have a free and competitive market, we believe it will continue to be to the benefit of both countries.

Senator EVANS. Is that your current assessment, that we've got a new government in Canada now, that both the—although I think that it's accurate to say that probably provincial attitudes are just as important as the federal attitude in Canada—that they are aimed in the direction of freer markets?

Mr. BOGGS. Yes, sir. Under the so-called western accords between the Central Government and the Provincial Governments, there was an indication that by, I believe, November 1 there would be a final arrangement struck on natural gas, but it was specifically stated that it would be in the direction of market-oriented pricing and trying to remove Canadian floor prices which have both kept prices higher and restricted Canadian sales. And to the extent that we have restrictions removed by the Canadian Government, that will be just as beneficial as removing restrictions on American production.

Senator EVANS. Do you have any clear sense of what's happened in Canada in the last 4 or 5 years in terms of exploration and reserves, as compared with what's happened in this country?

Mr. BOGGS. I can speak to that a little bit. I might be able to provide more explicit numbers. Canadian exploration took a very severe nosedive in 1981 with the introduction of the National Energy Program in Canada—the number of rigs drilling, the number of wells drilled went down fairly significantly.

[The information follows:]

Monthly Averages of Rotary Rigs Running
Canada and United States

Year/Month	United States	Canada
1978	2,259	272
1979	2,177	339
1980	2,912	405
1981	3,970	263
1982	3,105	200
1983	2,252	200
1984	2,229	259
1985		
January	2,452	330
February	2,188	393
March	1,955	395
April	1,877	148
May	1,865	166
June	1,858	304

Source: Hughes Tool Company.

Total Gas Wells Drilled
United States and Canada
(Wells Completed)

Year	United States		Canada	
	Number of Wells (thousand)	Footage (million feet)	Number of Wells (thousand)	Footage (million feet)
1978	14.42	75.71	3.39	10.74
1979	15.22	80.16	3.53	12.03
1980	17.25	90.68	4.33	15.16
1981	20.03	105.92	3.29	11.23
1982	18.79	103.72	2.62	7.70
1983	14.37	78.60	1.44	5.18
1984	15.55	86.99	1.93	5.95
1985	4.53[a]	25.34[a]	.77[b]	2.43[b]

[a] Data shown is for January through April, footage is calculated using average depth of 1984 wells. Comparable data for January through April 1984 is 4.78 for the number of wells and 26.74 for footage.

[b] Not available for all of Canada - data shown is for Western Canada - January through May. Comparable data for January through May 1984 is .50 for number of wells and 2.15 for footage.

Sources: Monthly Energy Review, March 1985, Annual Energy Review, 1984, and Canadian Petroleum Association, (phone conversation on July 2 and 8, 1985, with representative of CPA).

United State and Canadian Natural Gas
Reserves and Production
Billion cubic feet (Bcf)

	Canada			United States		
Year-End	Reserves	Production	R/P Ratio	Reserves	Production	R/P Ratio
1978	82,423	2,493	33.1	208,033	19,974	10.4
1979	88,593	2,340	37.9	200,997	20,471	9.8
1980	88,446	2,263	39.1	199,021	20,180	9.9
1981	90,936	2,406	37.8	201,730	19,956	10.1
1982	91,982	2,467	37.3	201,512	18,520	10.9
1983	92,730	2,226	41.7	200,247	16,822	11.9
1984	NA	2,442^{p}	--	NA	18,064^{p}	--

p = Preliminary.

Sources: Natural Gas Annual 1983, Volume I, and Monthly Energy Review, March 1985, DOE/EIA, Canadian Petroleum Association, and Oilweek, January 14, 1985.

Mr. **Boggs**. Over the last year, that appears to have turned around. Their drilling appears to be up. The projections, for what they are worth, made by drilling groups in the last few months in Canada have been for greater exploration. I do not have comprehensive numbers on Canadian reserve additions. I know their total reserves in terms of years of supply are much, much larger than ours. Their reserve-to-production ratio in natural gas, I think, is more than 50 years.

So they certainly have adequate supplies. They are making a number of significant exploratory discoveries in their offshore areas, and some of their onshore areas have continued to appear promising, as well.

Senator **Evans**. Mr. O'Connor, from FERC's viewpoint do you have any response to the series of regulations or directions you'd like to see us take and any influence it would have on our United States-Canada policy?

Mr. **O'Connor**. Well, we have asked in the notice of proposed rulemaking, we have asked on page 118 of the notice of proposed rulemaking, "The Commission requests comments on whether to include all costs of imported gas in block two."

So we will be receiving comments on how this competitive situation between the United States and the Canadian imports will be unfolding, and it's our—I think it's the intention within the notice of proposed rulemaking that all gas should be on the same competitive footing, and price signals should be accurately transmitted. The comprehensive nature of the proposal does include importation of Canadian gas, and we will be hearing I'm sure a lot on that during the comment period.

Senator **Evans**. Let me get back to your three-part billing mechanism to see if I understand it correctly. You're talking about allocating the old gas to historic or existing customers?

Mr. **O'Connor**. It's reserving the old gas.

Senator **Evans**. So a new customer coming along would be looking at a price then that would be essentially the price of new gas?

Mr. **O'Connor**. Yes.

Senator **Evans**. So that new customer—it's not the old postage stamp concept any longer? You'd be looking at marginal prices more accurately?

Mr. **O'Connor**. Yes.

Senator **Evans**. Has FERC thought about doing that same thing with electrical pricing?

Mr. **O'Connor**. Coincidentally, on May 30, the same day we issued the notice of proposed rulemaking, we did issue a notice of inquiry in the electric area. That is going to be conducted in two phases. The first phase will be directed toward our coordination sales responsibilities, as well as transmission service responsibility.

The second phase, which will be issued within the next 2 to 4 weeks, will be concerned with our requirements' responsibility and jurisdictional requirements sales; and as part of that, we will be looking at marginal cost pricing.

Senator **Evans**. If you look in marginal cost pricing, then you reserve the benefits of whatever extremely low cost production there is to historic customers?

Mr. **O'Connor**. I'm sorry, Senator?

Senator EVANS. You're then reserving the production, whether it's gas or electricity, of whatever extremely low cost production there is to historic customers? Those who already have it keep it?

Mr. O'CONNOR. In the gas area, because of the forever-regulated old gas, we have assumed—and I stress assumed—that the intent of Congress in the Natural Gas Policy Act by having forever-regulated old gas, is to reserve the old gas for the current—for the historical customers. That's the assumption that's behind that reservation.

We have stated that we do not have the regulatory authority to deregulate old gas. So we're not trying to do that. But that's the assumption behind that block 1 reservation.

Senator EVANS. Well, I'm sure that I'm stepping into mine fields that I know nothing about, and don't pretend to, in terms of the intricacies of the natural gas industry, but I guess I'm trying to probe to discover what—you know, leaving all regulation and whatever your perception might be on congressional intent aside—I'm trying to get at what you view as equity. Mr. Boggs may choose to get into this if he chooses.

Is it equitable or reasonable that you preserve to someone just because he's an existing customer a share of that resource, whether it's electrical or natural gas, to be forever more than competitive? It's tough for a new customer to come in and compete in the same field, then, with somebody who already has that existing resource.

Mr. O'CONNOR. Mr. Boggs might want to comment on the administration's position relative to total deregulation. [Laughter.]

Senator EVANS. I don't see anybody that wants to come up and face that pit.

Mr. BOGGS. As far as the FERC notice of inquiry on electricity, we are looking at it, and frankly in our analytical timetable it's a little bit behind the natural gas one, so I've really not taken a thorough look at it, whether it has the same kinds of implications or not.

Certainly the whole history of who is entitled to various types of electrical generation in the Northwest, as well as elsewhere, is a very controversial one, and it may be the appropriations bill still keeps us from even thinking about some changes. So really, we have not come to any conclusion on the FERC notice, but we will be looking at it.

Senator EVANS. OK. I understand, Senator Bradley, that if you have a question I would be pleased to yield, and maybe you can think about that one a little longer, and so will I, and maybe come back to it.

Senator BRADLEY. Thank you very much. I appreciate that, Senator Evans, and Mr. Chairman.

I would like to ask Mr. O'Connor, are there any pipelines in the country—and if so, how many—that move no gas, no gas, for another pipeline?

Mr. O'CONNOR. Any pipelines that move no gas for another pipeline?

Senator BRADLEY. Yes.

Mr. O'CONNOR. Or for anybody else?

Senator BRADLEY. Yes; only theirs.

Mr. O'CONNOR. I don't know the answer to that off the top of my head. I'd say most have transportation tariffs on file. Mr. Williams might be able to help us out on that. Mr. Williams is the Director of our Office of Pipeline and Producer Regulation.

Mr. WILLIAMS. Senator Bradley, there are roughly 120 so-called interstate pipelines in the country. There are probably 40 to 50 major pipeline companies. Now when you say are there no pipelines? Probably within the 120, there may be some that do not provide any transportation, but if there are any major pipelines, it would be very minuscule, because most interstate pipelines do provide transportation for other pipelines.

Senator BRADLEY. OK, as I understand your notice of proposed rulemaking on gas transportation, you've basically said that if the pipeline transports for anyone, they have to be willing to transport for all?

Mr. WILLIAMS. That's correct.

Senator BRADLEY. Chairman O'Connor, I understand that you've received a little heat on that ruling. I want to state publicly that I commend you for the ruling. I think that it is enormously important, and that it's a move that I think has the potential of delivering customers lower priced gas and improving the overall efficiency of the whole system, and I applaud you for it. We won't call it common carrier or contract carrier, but whatever we call it, the result happens to be enormously positive, and I commend you for it.

Mr. O'CONNOR. Thank you, Senator.

Senator NICKLES. Senator Evans.

Senator BRADLEY. Thank you, Mr. Chairman.

Senator EVANS. Let me just get back—I don't want to pursue this too much. It's obvious that it's a sticky wicket.

Let me get back, Mr. Boggs, just to natural gas where you do have a specific proposal, or FERC does have a specific proposal. Is it, in terms of more fundamental philosophy, is it the administration's position that it is appropriate for old gas to be preserved and the old price to be preserved for existing customers?

Mr. BOGGS. Well, that's one of the aspects of the notice. In my opening statement I indicated that we would be filing comments on all of this complex and interrelated pricing system. And that is certainly one of the aspects that has some positives and potentially some negatives.

The negative I think is, as you stated, is there a rationale for preserving those benefits to existing customers?

The positive is that it gets around the situation where, by rolling in all prices, some pipelines get a competitive edge for new service or new customers as well as some pipelines have an incentive to pay more because they have this so-called cushion to use up.

So it is not perfect, whichever way you go. I think we're going to be looking at that very carefully, but certainly the proposal does attempt to address some significant problems in existing markets that have been recognized by almost everyone, and this is one way to address them if you don't take other steps.

I do not have a position at the moment to say that FERC is exactly right, or not exactly right, but it is definitely an effort to address a real problem.

Senator EVANS. Take two companies, one existing and one new in the same field both in a business that has a very high use of natural gas either as feedstock, or fuel, or for whatever purposes, that that is a significant element in their ability to compete. Would the proposals of FERC and the direction they're taking make it virtually impossible for a new company to come in and compete effectively?

Mr. BOGGS. Well, let me say that offhand I don't think so, and let me give you my analysis.

Senator EVANS. I'm probing because I'm not sure it's the appropriate way to go.

Mr. BOGGS. OK. Let me give you a rough analysis, which is to say a couple of things.

First, old gas is no longer so cheap nor so plentiful as it once was where you had a difference of a factor of 10 or 20 in price. Now old gas may be a factor of 2 difference, and it may make up a smaller proportion. So that's diminished somewhat.

[The information follows:]

Projected Prices of Wellhead Purchases by NGPA Category,
Actual End of Month Oklahoma Spot Market Prices, and
Actual Average Price for Canadian Imports
(Dollars Per Thousand Cubic Feet)

		New Gas						
		Section						
	Old Gas[a] Price[b]	102[c] Price[b]	103[d] Price[b]	108[e] Price	109[f] Price	All New Gas[g] Price	Spot Market Price[h]	Average Canadian Price
1981 Total	1.22	2.97	2.69	3.38	2.27	2.89	NA	4.83
1982 Total	1.34	3.30	2.95	3.73	2.48	3.19	NA	4.98
1983								
January	1.39	3.46	3.03	3.85	2.47	3.33	NA	5.00
February	1.40	3.47	3.03	3.85	2.45	3.33	NA	5.06
March	1.42	3.50	3.07	3.93	2.50	3.38	NA	4.97
April	1.44	3.52	3.09	3.90	2.48	3.41	NA	4.62
May	1.42	3.56	3.09	3.90	2.48	3.42	NA	4.39
June	1.42	3.56	3.09	3.90	2.48	3.42	NA	4.40
July	1.40	3.57	3.10	3.91	2.47	3.43	NA	4.27
August	1.40	3.59	3.11	3.91	2.47	3.44	NA	3.90
September	1.35	3.65	3.11	4.05	2.44	3.47	NA	3.95
October	1.34	3.72	3.16	4.16	2.49	3.52	NA	3.98
November	1.38	3.71	3.16	4.16	2.49	3.54	NA	4.32
December	1.38	3.72	3.17	4.17	2.49	3.54	NA	4.32
Total	1.40	3.58	3.10	3.97	2.48	3.43	NA	4.49
1984								
January	1.41	3.76	3.20	4.18	2.52	3.59	NA	4.39
February	1.43	3.75	3.20	4.18	2.53	3.60	NA	4.30
March	1.45	3.77	3.21	4.05	2.51	3.61	NA	4.36
April	1.46	3.78	3.22	4.08	2.49	3.61	NA	4.13
May	1.43	3.79	3.22	4.09	2.49	3.61	NA	4.14
June	1.43	3.79	3.22	4.09	2.49	3.61	NA	4.06
July	R1.45	3.82	3.22	4.10	2.50	3.63	3.14	4.15
August	1.44	3.83	R3.22	R4.02	2.51	3.63	3.14	4.15
September	R1.46	3.91	R3.29	R4.26	R2.68	R3.69	2.99	4.15
October	R1.49	3.95	R3.39	R4.29	R2.71	R3.76	2.89	4.09
November	R1.58	3.94	R3.40	R4.30	R2.71	R3.76	2.94	3.34
December	R1.58	R3.93	R3.40	R4.29	R2.71	P3.76	2.73	3.22
Total	R1.47	3.83	3.27	R4.17	R2.58	R3.66	NA	4.01
1985								
January	R1.62	3.93	3.42	R4.31	R2.82	R3.76	2.73	NA
February	R1.61	R3.89	3.42	R4.33	R2.83	R3.74	2.63	NA
March	R1.57	3.87	R3.41	R4.33	R2.74	3.73	2.58	NA
April	R1.59	R3.82	R3.42	R4.28	R2.76	R3.69	2.63	NA
May	1.53	3.78	3.42	4.28	2.75	3.66	2.63	NA

See next page for footnotes and sources.

a Total of Sections 104, 105, and 106.
b Weighted average price.
c New natural gas and certain natural gas produced from the Outer Continental Shelf.
d New onshore production wells.
e Stripper well natural gas.
f Other categories of natural gas.
g Total of Sections 102, 103, 108, and 109.
h High price from high/low range reported for the Oklahoma Region converted from dollars per MMbtu by a factor of 1.031 Btu per cubic foot.

R - Revised data.
NA - Not available.

Sources: Projected prices by NGPA category from Table 22 of the April 1985 Natural Gas Monthly, actual end of month Oklahoma spot market price as published in Natural Gas Intelligence in the last issue of each month, and Canadian average prices from Form FPC-14, "Annual Report for Importers and Exporters of Natural Gas."

Mr. BOGGS. Secondly, the new company in your hypothesis, let's say a paint finishing firm which wished to start up, under the things that FERC is trying to do, it may make it possible for them to scour the country for the cheapest supplies and to have them transported to them in the best possible way, which is a situation they now wouldn't have. Certainly at the times when we had a moratorium on hookups, which is what we had in the not-too-distant past, that existing company was absolutely immune from competition, because a new company couldn't even get a hookup.

So I guess my first-blush thought is that I see the potential for the problem you assert. There are some opposing forces, and this proposal by FERC is also in effect an interim mechanism, as the old gas inexorably declines if we stay under the current regime. So as I say, it remains an open question, but I think the evil that you raise may not be as serious. There's certainly a possibility there, however.

Senator EVANS. Thank you, Mr. Chairman.

Senator NICKLES. Senator Evans, thank you.

A couple of questions. Mr. Boggs, just trying to analyze the cost of imports, and particularly Canadian imports, but the cost of imports, would you supply that for the committee?

Mr. BOGGS. Certainly we can.

[The information follows:]

Natural Gas Imports from Canada and Average Prices, 1977-1984
(Volume in Million Cubic Feet; Average Price in Dollars per Thousand Cubic Feet)

	Canada					
	Interstate		Intrastate		Total	
	Volume	Average Price	Volume	Average Price	Volume	Average Price
1977 Total	953,585	1.99	43,137	2.00	996,722	1.99
1978 Total	842,567	2.19	38,556	2.21	881,123	2.19
1979 Total	959,582	2.61	41,193	2.59	1,000,775	2.61
1980 Total	763,476	4.32	33,031	4.28	796,507	4.32
1981 Total	730,309	4.83	31,798	4.77	762,107	4.83
1982 Total	759,415	4.98	23,992	4.94	783,407	4.98
1983						
January	84,059	5.00	1,636	4.91	85,695	5.00
February	69,921	5.07	1,399	4.93	71,320	5.06
March	61,442	4.98	1,319	4.89	62,761	4.97
April	55,022	4.62	1,062	4.55	56,085	4.62
May	47,158	4.39	731	4.34	47,889	4.39
June	40,176	4.40	547	4.33	40,724	4.40
July	41,440	4.28	773	4.08	42,213	4.27
August	43,838	3.91	881	3.82	44,719	3.90
September	50,975	3.95	943	3.69	51,918	3.95
October	51,505	3.98	1,211	3.63	52,716	3.98
November	63,124	4.32	1,784	4.07	64,907	4.32
December	88,380	4.33	2,597	4.08	90,976	4.32
Total	697,040	4.49	14,883	4.30	711,923	4.49
1984						
January	86,554	4.40	2,788	4.06	89,342	4.39
February	59,491	4.31	2,303	4.05	61,794	4.30
March	59,084	4.39	2,010	3.97	61,094	4.38
April	58,619	4.13	1,325	4.01	59,943	4.13
May	55,726	4.15	1,243	3.98	56,968	4.14
June	49,456	4.07	1,018	3.99	50,474	4.06
July	46,268	4.15	960	4.07	47,228	4.15
August	47,577	4.15	925	4.00	48,502	4.15
September	50,286	4.16	1,124	3.73	51,410	4.15
October	56,284	4.09	1,329	3.76	57,613	4.09
November	77,037	3.32	2,141	4.06	79,179	3.34
December	89,341	3.21	2,479	3.85	91,820	3.22
Total	735,723	4.01	19,645	3.97	755,368	4.01

Note: Totals may not equal sum of components due to independent rounding.
Source: Form FPC-14.

Senator NICKLES. I'm glancing at the information from EIA, but if you'd just add that to the other information I had asked for, I would appreciate that.

Mr. BOGGS. Certainly.

Senator NICKLES. In dollar cost. Also, the volume and price. Do you know the price right now of Canadian imports?

Mr. BOGGS. Well, it varies somewhat. As I say, it's in the general area of about $3. I think it's a little bit different in the Northeast from the West, and also under the new regulations that the United States has adopted, as well as some of the Canadian, it's possible to have individual deals or individual price. A few years ago, we could say the Canadian price is exactly $4.94, let's say. Now it's becoming more varied. I can certainly provide you with an average for each of the last several months, and I may be able to have some breakdown by area of importation.

[The information follows:]

Pipeline Natural Gas Imports, 1983-1984

Importing Companies	Point of Entry	Volume (thousand cubic feet)		Percentage Change	Average Price			
					Dollars/Thousand Cubic Feet		Dollars/Million Btu	
		1983	1984		1983	1984	1983	1984
Imports from Canada								
Interstate								
ANR Pipeline Co.[a]	Noyes, Minn.	12,851,350	40,064,541	211.8	4.49	3.79	4.51	3.82
Boundary Gas, Inc	Niagara Falls, N.Y.	0	2,440,000	--	0	4.35	0	4.39
Great Lakes Gas Transmission Co.	Noyes, Minn.	43,884,639	[b]43,471,237	-0.9	4.51	4.31	4.55	4.35
Inter-City Minnesota Pipelines, Ltd.	Warroad, Minn.[c]	5,635,872	[d] 5,472,385	-2.9	3.64	3.63	3.67	3.66
Midwestern Gas Transmission Co.	Noyes, Minn.	36,966,500	55,722,252	50.7	4.53	4.11	4.57	4.14
Natural Gas Pipeline Co. of America	Port of Morgan, Mont.	10,554,342	2,162,028	-79.5	4.83	4.30	4.59	4.31
Northern Natural Gas Co.[e]	Noyes, Minn.	10,142,966	16,282,465	60.5	4.54	4.91	4.58	4.95
	Monchy, Saskatchewan	11,297,905	13,571,365	20.1	4.70	4.36	4.60	4.38
Northwest Alaskan Pipeline Co.	Kingsgate, B.C.	38,737,552	45,339,229	17.0	4.60	3.90	4.65	3.91
	Monchy, Saskatchewan	110,750,668	115,328,084	4.1	4.83	3.95	4.66	3.98
Northwest Pipeline Corp.[g]	Sumas, Wash.	85,600,403	89,829,950	4.9	4.61	3.97	4.51	3.84
	Kingsgate, B.C.	23,170,541	21,739,204	-6.2	4.56	3.82	4.56	3.84
Pacific Gas Transmission Corp.	Eastport, Idaho	248,903,352	232,281,828	-6.7	4.28	3.98	4.28	4.00
Reichhold Chemicals, Inc.	Sumas, Wash.	0	95,000	--	0	3.12	0	3.15
Tennessee Gas Pipeline Co.	Noyes, Minn.	14,694,108	12,310,867	-16.2	4.54	4.24	4.58	4.27
Texas Eastern Transmission Corp.	Noyes, Minn.	20,913,506	17,094,120	-18.3	4.12	4.01	4.15	4.04
Transcontinental Gas Pipe Line Corp.	River Rouge, Mich.	6,951,112	3,683,247	-47.0	4.43	4.37	4.43	4.37
	Niagara Falls, N.Y.	15,979,575	18,834,878	17.9	4.25	3.70	4.21	3.66
Total Interstate		697,040,407	735,722,680	5.5	4.49	4.01	4.45	4.01
Intrastate								
The Montana Power Co.	Whitlash, Mont.	2,621,083	6,525,951	149.0	4.20	4.03	4.39	4.20
	Babb, Mont.	1,163,719	1,281	-99.9	4.80	4.39	4.79	4.41
	Port of Del Bonita, Mont.	120,020	72,672	-39.5	5.56	5.02	4.60	4.66
St. Lawrence Gas Co., Inc.	Massena, N.Y.	6,368,026	8,050,847	26.4	4.24	3.90	4.28	3.92
Vermont Gas Systems, Inc.	Highgate, Vt.	4,609,900	4,994,247	8.3	4.27	3.99	4.31	4.02
Total Intrastate		14,882,748	19,644,998	32.0	4.30	3.97	4.35	4.04
Total Canada		711,923,155	755,367,678	6.1	4.49	4.01	4.45	4.01

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[a] Michigan Wisconsin Pipe Line Co. was changed to ANR Pipeline Co. effective January 1, 1984.

[b] In addition, 265,904,118 thousand cubic feet were received from TransCanada Pipelines Ltd. for transportation, all of which was delivered to TransCanada at St. Clair and Sault Ste. Marie, Michigan.

[c] Includes small quantities shipped through International Falls, Minnesota, point of entry.

[d] Includes a net import of 306,620 thousand cubic feet based on 8,317,378 thousand cubic feet received from TransCanada Pipelines Ltd. for transportation and 8,010,758 thousand cubic feet redelivered to TransCanada Pipelines Ltd. at Baudette, Minnesota.

[e] Northern Natural Gas Co. (CP70-69; CP70-70) delivered 11,818,786 thousand cubic feet of gas to Consolidated Natural Gas Co. (Canada) at a point on the Montana-Saskatchewan Border, near Willow Creek, Saskatchewan, for transportation and received 11,652,370 thousand cubic feet of gas at Noyes, Minnesota, in 1984. These volumes represent the approximate equivalent quantity in Btu.

[f] Includes "take-or-pay" deficiency payment of $9,177,120.

[g] In addition, Northwest Pipeline Corp. (CP83-214) imported from Canada 1,635,688 thousand cubic feet for storage in 1983 and returned to Canada 666,285 thousand cubic feet, leaving a balance of 969,403 thousand cubic feet intransit gas in storage as of December 31, 1983. During 1984, 1,077,597 thousand cubic feet were imported for storage and 1,001,775 thousand cubic feet were delivered back to Canada, leaving a total balance of 1,045,225 thousand cubic feet intransit gas in storage as of December 31, 1984.

-- = Not applicable.

Source: Form FPC-14.

Senator NICKLES. Well, I'm looking at Energy Information Administration data for the last several months, and during the first 10 months of 1984 is over $4, and then it shows November at $3.43, and December at $3.34, and it shows January 1985 at $3.21.

Mr. BOGGS. Yes; that was when the price—there was a general price reduction under the so-called volume-related incentive program. And so if it says $3.20 or something, that was the range that I had indicated.

Senator NICKLES. I was thinking the volume-related incentive program was just for their marginal sales, not for their base sales.

Mr. BOGGS. But I think the way that was—I'd have to give you the exact details, but the way it works out was that it brought it down pretty sharply then. They're now going forward to essentially a market-based system. So that I would anticipate that those prices would stay in that latter vicinity of about $3, or perhaps even come down lower.

Senator NICKLES. I would hope that they would continue coming lower, and I've expressed this to the Canadian Ambassador and others. It's still above our market price.

Mr. BOGGS. For our average price. It's not necessarily above the marginal higher priced end of our range.

Senator NICKLES. Well, let me ask you this question: Is Canadian gas any older or any newer than American gas?

Mr. BOGGS. Well, but they don't——

Senator NICKLES. Did the Good Lord create their gas before or after our gas?

Mr. BOGGS. No; but the Good Lord kept it out of the hands of the Natural Gas Policy Act. [Laughter.]

So gas——

Senator NICKLES. For that very reason, many people have taken the Lord's name in vain when we're talking NGPA. [Laughter.]

Mr. BOGGS. Gas is old or new only as a result of the actions of the Federal Government or those acting under its authority. And so you certainly have a point, that if you look at it on an average basis it's higher; if you look at it as a marginal supply, it's right in the same range as our current marginal supplies would be my——

Senator NICKLES. I would correct you on that, because our marginal supplies in the lower 48 anyway are substantially—still substantially less than Canadian imports, even at $3.21. We have gas selling for $2.60, $2.50 in our neighborhood. We may have some gas that might be up on that higher range, but I think you'll find it's still above the average market shut-in gas prices that we have in the lower 48. But if you would provide that I would appreciate it.

Mr. BOGGS. We will provide data on that.

[The information follows:]

I would correct you on that, because [prices for] our marginal supplies in the lower 48 anyway are substantially -- still subtantially less than Canadian imports, even at $3.21. We have gas selling for $2.60, $2.50 in our neighborhood. We may have some gas that might be up on that higher range, but I think you'll find it's still above the average market shut-in gas prices that we have in the lower 48.

A.

The Department has no data on which NGPA categories of gas are currently being shut-in in particular states. However, the price of previously shut-in gas that has been released from or was not originally dedicated under a long-term contract (i.e., "spot market" gas) in Oklahoma sold for as much as $2.58 to $2.73 per mcf from January through May of this year. This is much cheaper than the average Canadian price, but that price includes Canadian demand charges. These charges cover all the Canadian pipelines' fixed costs. The marginal cost of the Canadian gas alone at the border is embodied in the commodity charge. The Canadian gas price at the border, minus the demand charge, ranged from $2.40 per mcf for SoCal to $2.95 per mcf for PG&E in early 1985.

Senator NICKLES. Mr. O'Connor, one final question on your proposed rulemaking. What are the dates? You're still receiving inputs on it?

Mr. O'CONNOR. Yes. We issued it on May 30. The comment period runs until July 15. We have a public conference scheduled for July 30, and the Commission and staff will then be reviewing the comments. And I would hope that, depending on whatever we do if anything, dependent on the comments, I would certainly hope that we would be able to do whatever we may be doing by the end of this year, and particularly for the winter season.

Senator NICKLES. By the end of?

Mr. O'CONNOR. By the end of this year, 1985.

Senator NICKLES. Let me say that I would concur with Senator Bradley's comments. As you're well aware, as is most everyone that's tried to analyze the rulemaking, it's very complicated and not the easiest subject in the world. But I do compliment you. Was the decision by the Commission unanimous?

Mr. O'CONNOR. Yes; it was.

Senator NICKLES. Well, again, I compliment you and all the members of the Commission, maybe not on every single detail of the NOPR, but the thrust of your efforts I think are to be commended for helping us move toward a more market-oriented natural gas policy, and again in some of these areas that aren't the easiest thing in the world.

There is something that I need to clarify. I asked you a question about take-or-pay relief, and you started talking about the 25-percent reduction for LDC's. Those are two separate issues, are they not?

Mr. O'CONNOR. Yes, they're two separate parts. The take-or-pay is part B, and the other is C or D. So they're two separate parts. But I keep stressing, Mr. Chairman, the interrelationship and the package-nature of this. They are all interrelated and, you're correct, there are individual pieces that somebody may be unhappy with, but I have tried to stress at our public meeting and I've stressed in the opening remarks, that it is a package.

We would hope that all the industry participants would look at it as a package and try to net out the pluses and the minuses, and hopefully there'll be a net plus that's going to serve the country and consumers.

Senator NICKLES. Has there been a general response, negative or positive, say from the pipeline sector?

Mr. O'CONNOR. We have not had any responses. There have been some unidentified comments in some of the trade press over the past weeks, and it's been a mixed response; but there have been no comments that I know of. And I believe that because of the complexity of the overall proposal, indeed all segments of the industry are looking hard at it and are trying to sort out what their comments will be to meet the July 15 comment period.

Senator NICKLES. I'm aware of that, and I hope that today's hearing will help clear up some of that confusion, and I appreciate your cooperation.

I also have some additional questions for you that I will submit for the record, as well.

Mr. O'CONNOR. Surely.

Senator **Nickles**. And to our panelists, and Mr. Williams, as well, we appreciate your input and cooperation before the committee. The committee is adjourned.

Mr. **O'Connor**. Thank you.

[Whereupon, at 11:08 a.m., the hearing was adjourned, subject to the call of the Chair.]

NATURAL GAS MARKET

THURSDAY, JULY 11, 1985

U.S. SENATE,
SUBCOMMITTEE ON ENERGY
REGULATION AND CONSERVATION,
COMMITTEE ON ENERGY AND NATURAL RESOURCES,
Washington, DC.

The subcommittee met, pursuant to notice, at 9:39 a.m., in room SD-366, Dirksen Office Building, Hon. Don Nickles presiding.

Present: Senators Nickles, Hecht, Ford, and Rockefeller.

Also present: Howard Useem, professional staff member; and Elizabeth Moler, counsel for the minority.

OPENING STATEMENT OF HON. DON NICKLES, A U.S. SENATOR FROM THE STATE OF OKLAHOMA

Senator NICKLES. Today is the second day of subcommittee hearings exploring the state and factors affecting the natural gas market.

At the first day of hearings on June 18, the subcommittee received testimony from the Chairman of the Federal Energy Regulatory Commission and the Deputy Secretary of the Department of Energy. Today we will hear from private sector witnesses.

Today we will focus on two key areas: first, how has the partial decontrol of natural gas on January 1, 1985, affected price and supply, and also, to what extent has partial decontrol exacerbated Government-induced distortions in the marketplace; second, asking everyone to get out their crystal ball, what may occur in the marketplace in the future, particularly in light of the FERC's notice of proposed rulemaking on pipeline regulations.

On both panels today we have representatives of producers, pipelines, distributors and end users, both industrial and residential.

I want to commend all of you for your participation and also for your statements. I look forward to your statements today and seeing your comments, particularly as they pertain to the notice of proposed rulemaking and what you guess will happen in the future.

In our first panel we have a list of distinguished gentlemen who are experts in the field: Nick Bush, who is president of the Natural Gas Supply Association; Jerry McGrath, president of the Interstate Natural Gas Association of America, INGAA; Bill Terpstra, president of the Natural Gas Pipeline Co. of America; Bud Lawrence, president of the American Gas Association; Jack Elam, vice president and general counsel of Cone Mills Co. and chairman of the Process Gas Consumers Group and Edward Sheehy, vice president of productivity, Management and Operating Services of Hercules, representing the Petrochemical Energy Group, accompanied by Gordon Gooch, as well.

Gentlemen, we appreciate your participation before the committee today.

We would request that all of our panelists try to keep their remarks limited to 8 or 10 minutes.

Mr. Bush, we will start with you.

STATEMENT OF NICHOLAS J. BUSH, PRESIDENT, NATURAL GAS SUPPLY ASSOCIATION

Mr. BUSH. Mr. Chairman, my name is Nicholas J. Bush. I am president of the Natural Gas Supply Association. NGSA is a trade organization that represents major, medium-sized and independent natural gas production companies that produce approximately 80 to 85 percent of the Nation's natural gas energy.

In the interest of time, Mr. Chairman, I would ask that I be allowed to summarize my comments, and that my full comments be entered into the record.

Senator NICKLES. I would appreciate that and will enter everybody's statements into the record.

Mr. BUSH. Mr. Chairman, we appreciate the opportunity to participate in these timely hearings.

The natural gas industry is going through a significant transitional period, and it's important to provide a public policy forum for review of the issues associated with this transition.

You're to be commended in particular, Mr. Chairman, for the leadership you're providing in that regard and for your continued high level of interest in natural gas issues.

Mr. Chairman, we've asked the staff to extract four charts which are part of the association's filed comments. In these oral remarks, I'd like simply to speak to these charts, and if they haven't been extracted, they're attachments one through four on my file statement.

As a background, it might be helpful to recall that last year, there were frequent predictions made with quite a great degree of certainty that the advent of NGSA's partial deregulation would bring skyrocketing prices and potential financial disaster, in particular to interstate pipelines, unless legislative proposals to abrogate certain contractual commitments, such as take-or-pay and indefinite pricing clauses, were adopted.

Fortunately, the Congress was not persuaded to do so.

Obviously, natural gas prices have not flown up. In fact, if you would direct your attention to attachment one of my statement, gas prices at the wellhead are obviously declining or stable. In particular, there has been a major decline of wellhead spot prices in most of the major gas producing areas over the last year. Oklahoma prices, I'd note, have been the lowest for the longest period of time. And spot prices are still dropping. According to the Natural Gas Intelligence Report of July 8, 1985, domestic natural gas spot prices in Texas, Louisiana, and Oklahoma range now from $2.25 to $2.65 a million Btu's, down between 15 and 40 cents just 3 months ago.

The second chart portrays what you might logically expect to happen. The clear impact of lower wellhead natural gas pricing as been reduced drilling activity. The number of exploratory wells drilled for gas—that's those wells that are drilled in new areas or deeper, untested, depths to discover new fields, as differentiated from development wells, which are drilled in and around fields already discovered—in each of the last 4 years has declined steadily. In fact, there were 37 percent fewer exploratory gas wells drilled in 1984 than in 1981. Moreover, a severe tile toward the exploration for oil has returned in 1984 with exploratory drilling for new gas fields, which, as recently as 1981, had been fairly evenly matched with oil exploration, now at half the level of exploratory drilling for oil.

I might note also, Mr. Chairman, that overall drilling activity, as you know, is at quite low levels, both for oil and gas. And what is particularly troublesome this year, that has not been noted in the past, is that normally in the opening months of the spring there is a rebounding activity, as you would expect, in drilling. That rebound certainly has not occurred this year. And so, the prospects for the remainder of 1985 with respect to drilling we're afraid are quite worrisome.

Attachment 3 shows the natural gas reserve additions and production. Significantly less exploratory activity has resulted in less gas discovered. Addition to gas reserves for each year since 1977 has fallen well short of production. In fact, excluding the discovery of gas reserves at Prudhoe Bay, AK, in 1970, gas production has exceeded discovery of gas reserves for every year since 1967, or nearly 20 years.

I get into a disagreement on occasion with my good friend, Bud Lawrence, to the left, on the interpretation of gas reserve additions. It usually comes down to whether or not you include statistical adjustments within the field of gas reserve adds. But we're fairly confident, and its been adopted, and we feel it's indicative that gas reserve additions have simply not kept up with production for the past 20 years.

The final attachment I'd like to direct your attention to is what we call our ski slope of proved reserves of natural gas.

Because of this continual excess production in relation to reserve addition, the nation's total proved reserves, of domestic reserves, has dropped off sharply. Particularly troublesome is the fact that, of the 209 or 210 trillion cubic feet of proved reserves, 35 trillion cubic feet of those are in Alaska, which may or may not be economic in the foreseeable future for delivery to the lower 48.

Total gas reserves available for production at this time are at or below a 10-year supply level, based on current consumption. And I understand, Mr. Chairman, the difficulty, at a time when we are enjoying right now a tremendous deliverability surplus, it's very, very difficult to get anyone to focus on the long-term reserve status of this nation, particularly with respect to natural gas. But we feel it demands someone's attention, and we're very happy that you've provided the opportunity to focus some of that attention on that situation.

We're also very pleased at your willingness to continue to advocate total deregulation of natural gas at the wellhead.

As you know, there are a number of studies, including those that have been done by independent government agencies, that conclude that the nation will sacrifice as much as 50 trillion cubic feet of potential natural gas production if current gas pricing policy runs its course.

There are a number of legislative proposals currently before the Congress which would affect natural gas policy. We appreciate that you have continued to include deregulation as part of your legislation, proposed legislation.

As we told your staff, we wish you would have included even more of the gas that would be covered under those deregulation aspects. We also remain quite adamant that if legislation were to be considered before a comprehensive nondiscriminatory transportation program could be implemented by a regulatory body, the FERC, we would ask that that be considered in your legislation as well as any other.

I think the notice of proposed rulemaking, Mr. Chairman, has been issued. We're in the process of preparing our final comments that will be submitted on Monday to the Federal Energy Regulatory Commission. I haven't addressed those in these oral remarks.

I can tell you that there are significant and growing concerns within the producing industry over certain aspects of the NOPR, particularly with the block billing pricing concept. We are, as I said, preparing to file those comments, and I would ask that the record be held open long enough so that we might submit a copy of our response to the Federal Energy Regulatory Commission and that it might be made a part of this record.

Senator NICKLES. Do you plan on doing that next Monday?

Mr. BUSH. Yes.

Senator NICKLES. OK.

Mr. BUSH. Thank you, Mr. Chairman.

[The prepared statement of Mr. Bush follows:]

TESTIMONY

OF

NICHOLAS J. BUSH

FOR THE

NATURAL GAS SUPPLY ASSOCIATION

BEFORE THE

U.S. SENATE

SUBCOMMITTEE ON ENERGY REGULATION & CONSERVATION

COMMITTEE ON ENERGY AND NATURAL RESOURCES

ON

THURSDAY, JULY 11, 1985

My name is Nicholas J. Bush. I am President of the Natural Gas Supply Association (NGSA), a trade organization representing major, medium-sized and independent natural gas production companies which market about 80 - 85 percent of the nation's natural gas energy.

NGSA appreciates this opportunity to participate in these timely hearings on the current state of natural gas markets.

A REVIEW OF THE NATURAL GAS POLICY DEBATE

During the past three years, the Congress and others in the public sector as well as many in the private sector have debated the wisdom of the nation's natural gas policy. NGSA has participated actively in those discussions, advocating comprehensive, market-oriented solutions to what our membership believes are the gas market inequities and distortions that have been created by past legislative and regulatory decisions. We have consistently urged that deregulation of all natural gas at the wellhead be achieved at the earliest possible date. We have also opposed any "windfall" or excise tax upon gas freed from price controls. In addition, NGSA supports equal access for all buyers to natural gas from any and all sources, onshore and offshore; non-discriminatory contract carriage: and the removal of all end-use restrictions on natural gas, including repeal of the incremental pricing provisions of Title II of the Natural Gas Policy Act (NGPA) and the Fuel Use Act.

We recommended the rejection of piecemeal legislative proposals that would have maintained or extended wellhead price controls and/or abrogated certain portions of natural gas contracts -- namely, take-or-pay and indefinite pricing clauses. These proposals, it was argued by some at the time, would remove the problems which were expected to develop in the partially deregulated environment scheduled to begin on January 1, 1985, under the Natural Gas Policy Act (NGPA).

Many had predicted that the partial deregulation of the NGPA would result in price "fly-ups" and financial disaster for interstate pipelines. In fact, the American Gas Association (AGA) predicted at one point that gas prices would increase 39% after 1/1/85 if the NGPA were allowed to run its course1/. Around the same time, the Citizens/Labor Energy Coalition (C/LEC) predicted an increase of 58%2/ while somewhat later, the Interstate Natural Gas Association of

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1/ "Winter 1983 AGA-TERA Base Case," February 8, 1983, p. 2.

2/ "Gas Prices Out of Control: The Cost of Inaction," Citizen/Labor Energy Coalition Study, February, 1983.

America (INGAA) predicted price increases on the magnitude of 9 - 12%[3].

NGSA maintained throughout the natural gas policy debate that producers and pipelines would work toward negotiated solutions of whatever problems may exist within their contractual arrangements. We also were confident that there would not be rapid price increases as a result of either the partial deregulation called for by the NGPA or complete deregulation. Both assertions have been borne out during the six months since price controls have been lifted on some categories of natural gas.

NATURAL GAS MARKET REALITIES

Immediately before and since NGPA's partial deregulation took effect, pipelines have reported producer concessions on take-or-pay issues. In a report prepared for NGSA by Foster Associates, it was revealed that the total expected relief granted by producers during 1984 was estimated at $3.2 billion or about one-third of the total cumulative take-or-pay obligations[4].

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[3] "Analysis of Price Fly-Up Under the Natural Gas Policy Act," Interstate Natural Gas Association of America, April 1984.

[4] Foster Associates "Analysis of the Take-or-Pay Problem" prepared for the Natural Gas Supply Association, March 1984.

Press accounts continue to report take-or-pay settlements made by producers and pipelines. For example, it is reported that Panhandle Eastern Corporation settled $2 billion in take-or-pay obligations attributable to Panhandle Eastern and Trunkline pipelines for a payment of $195 million[5]. Reportedly, United Gas Pipeline's take-or-pay obligations have been reduced by as much as $800 million through settlement payments in cash and kind of $79 million[6]. Producer concessions have occurred despite the fact that there is strong evidence that interstate pipelines are quite capable of absorbing much of these freely agreed to contractual commitments. (See Appendix A attached hereto, "Comparison of Natural Gas Transmission Company Rates of Return and Risk with Other Regulated and Non-Regulated Industries.")[7].

Obviously, natural gas prices have not "flown up." In fact, natural gas prices at the wellhead are either stable or declining (see Attachment #1). In particular, there has been a major decline of wellhead spot prices in most of the major gas producing areas over the last year.

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[5] "Inside FERC," April 1, 1985, p. 2.

[6] "Natural Gas Intelligence", April 15, 1985.

[7] Docket No. RM85-1-000 (Phases II & III); Initial Comments of the Natural Gas Supply Association, Appendix A, filed March 11, 1985.

And spot gas prices are still dropping. According to the Natural Gas Intelligence report of July 8, 1985, domestic natural gas spot prices in Texas, Louisiana and Oklahoma now range from $2.25 to $2.65 per million Btu's -- down between 15 and 40 cents from just three months ago.

GAS SUPPLY SITUATION

The clear impact of lower wellhead natural gas prices is reduced drilling activity (see Attachment #2). The number of exploratory wells drilled for gas -- that is, those wells drilled in new areas or deeper, untested depths to discover new fields as differentiated from development wells which are drilled in and around fields already discovered -- in each of the last four years has declined steadily. There were 37% fewer exploratory gas wells drilled in 1984 than in 1981. Moreover, a severe tilt toward the exploration for oil returned in 1984, with exploratory drilling for new gas fields (which as recently as 1981 has been fairly evenly matched with oil exploration) at half the level of exploratory drilling for oil.

Significantly less exploratory activity results in less gas discovered (see Attachment #3). Additions to gas reserves, that is, new gas discoveries, for each year since 1977 has fallen well short of production. In fact, excluding the discovery of gas reserves at Prudhoe Bay, Alaska in 1970, gas production has exceeded discovery of gas reserves for every year since 1967 or nearly 20 years.

Because gas production has exceeded reserve additions for many years, the nation's total proved domestic reserves, therefore, have dropped off sharply as shown in Attachment #4. Particularly troublesome is the fact that the nation's proved reserves of 200 trillion cubic feet include 35 trillion cubic feet of Alaskan gas discoveries which may not be economic for delivery to the lower 48 states for some time. Total gas reserves available for production are at or below a ten-year supply level based on current consumption.

At a time when the nation still has a surplus deliverability of gas, it is often difficult to focus attention on the fact that we need to accelerate our search for new supplies.

THE SITUATION BEYOND THE WELLHEAD

Supply and demand should reach equilibrium in a market free of distortions and when price signals are allowed to be transmitted accurately between the wellhead and the burnertip. There is mixed evidence as to whether or not wellhead price reductions are being fully realized by gas consumers.

Based on the Energy Information Administration's survey of 25 major metropolitan areas, residential gas prices declined in 14 cities and increased in 11. However, on average, residential prices nationwide for the winter season

-- that is December, January and February -- actually increased from $6.02/Mcf in the 1983/84 winter season to $6.13/Mcf in the 1984/85 winter season.

This residential price increase is of interest when it is compared to the weighted average cost of gas purchases by the major interstate pipeline systems for 1983 and for the period most recently available (see Attachment #5).

At the same time average residential costs increased by 11¢/Mcf, that is, from $6.02/Mcf to $6.13/Mcf, the cost of gas purchased by eleven of the major interstate pipelines declined by anywhere between 6¢/MMBtu to 99¢/MMBtu.

Market distortions are thus characterized by this contradiction in natural gas prices which at the wellhead are under severe downward pressure, but which result in certain burnertip prices increasing on average.

A look into the recent history of expanding pipeline and distribution company costs should provide some clarification of this phenomenon (see Attachment #6).

Wellhead costs when compared with pipeline and distribution company costs from 1981 to 1984 reveal that the wellhead cost per Mcf rose 65 cents during this period, while the transmission and distribution charges rose $1.12.

These transmission and distribution charges represent a pipeline's margin, that is, the cost difference between the wellhead and the burnertip prices. Until recent years, little attention was paid to margins downstream from the gas well. Virtually all the gas that could be produced was sold in an environment in which the price of the commodity was regulated well below its market value.

However, as the burnertip price of natural gas began to approach market clearing levels, gas producers increasingly were told that it was necessary for them to absorb certain price reductions to preserve markets. As a result, significant questions have been raised as to whether the regulated sectors of the industry are exercising the same discipline as to costs that is being demanded of producers.

Attachment #7 illustrates what happened to pipeline and distributor margins between 1973 and 1983. Here "margin" is defined as the difference between the average price of gas to consumers and the average wellhead price.

Looking at the 10-year period, the regulated sectors' margin increased four-fold from 57 cents to $2.53/Mcf. If the margin had increased at a rate of inflation during these years, it would have been $1.24 in 1983, not $2.53/Mcf. This reveals a difference, or excess margin growth, of $1.29/Mcf.

This margin increase of $1.29 over inflation was the result of a market vacuum which exists between the low cost of regulated gas from 1973 and the higher cost of alternate fuels, the prices of which were unregulated and market sensitive. When a price disparity exists between competing commodities, there is room to squeeze in added margins. This "squeezing" has clearly happened to some degree in the pricing of natural gas.

An examination of pipeline rates of return and risk reveals that excess margins can exist in the utility portion of the gas industry. Appendix A (referred to earlier in these comments) analyzes pipeline rates of return and risk. Three points emerge from this analysis irrespective of the measure used, whether it be return on equity or return on capital:

- First, pipelines receive the highest return on any company grouping; better than Standard and Poor's Industrial 400 or Standard and Poor's Distribution Companies or Moody's Electric Utility Group (See Attachment #8);

- Second, the analysis indicates that natural gas pipelines experienced the lowest degree of risk in terms of the variability measured here, when compared to other company groups; and,

- Finally, pipeline returns have been protected by Federal regulation from the adverse consequences of high inflation.

Producers need a healthy interstate pipeline industry. After all, pipelines provide the only viable transportation of gas to market. But legislative and regulatory policies should allow pipelines a fair opportunity to recover their costs and earn reasonable returns, not guarantee them high rates of return, regardless of performance.

ACTIVITIES AT THE FEDERAL ENERGY REGULATORY COMMISSION (FERC)

With the demise of all legislative activity at the end of the last session of Congress, the Federal Energy Regulatory Commission (FERC) aggressively moved to address commonly perceived natural gas market problems. The Commission issued three Notices of Inquiry into the transportation, marketing and rate structure of interstate pipelines.

NGSA told the FERC in its responses to the inquiries that a comprehensive rulemaking was required to make pipeline operations more efficient and market responsive.

Briefly, we recommended to the Commission that it make substantial changes in two principal areas: rate design and transportation policies.

In the area of rate design, we asked specifically that any changes in pipeline ratemaking be part of a regulatory overhaul which includes allowing currently regulated prices to rise toward market levels and which revises abandonment procedures consistent with Section 7 of the Natural Gas Act.

We have stated that the structure of rates should enhance the marketability of gas, maximize potential throughput, impart more competitive risks on interstate pipelines and eliminate any bias toward the purchase of imported gas volumes.

As for transportation, we have recommended that access to interstate transportation services be facilitated and that non-discriminatory contract carriage be applied to both pipelines and distributors so that potential shippers have the opportunity to get gas to users.

Interstate pipelines are regulated utilities, granted certificates of public convenience and necessity which preclude free entry by competitors. Competition is limited by definition. Furthermore, many producing regions have only a single pipeline supplier. This situation may increase rapidly, due to a growing number of mergers. Producers who had experienced the competitive environment posed by the existence of at least four potential buyers and transporters of their gas, namely, Transwestern, Houston Natural Gas, Florida Gas and Northern Natural, will soon see those companies as just one buyer and the market environment as less competitive.

This growing concentration of the interstate pipeline system is a major concern for producers and consumers. If, as the Chairman of InterNorth recently predicted, there are to be just five or six major interstate pipelines that survive the current trend toward consolidation, what does that mean for the thousands of producers who will compete to sell gas to them? Or, for the hundreds of thousands of consumers whose gas purchase costs will be dictated by a single pipeline supplier?

Non-discriminatory contract carriage will remove the wall between buyers and sellers of gas, allowing producers to maximize their sales volumes and buyers to increase their use of gas.

Arguments are sometimes made that strong, non-discriminatory carriage will fail because sufficient capacity does not exist in the interstate system to handle a vigorous carriage trade -- that during peak times carriage gas would displace firm contract supplies.

On the contrary, as Attachment #9 shows, there is a wide difference in the peaks and valleys of annual consumption and in the maximum day sendout trend on an interstate pipeline's system. It suggests that capacity is available, even on peak days.

It is said that the level of so-called "voluntary carriage" in 1984 was 6.8 trillion cubic feet[8/]. However, an examination of that claim reveals that only 1.1 trillion cubic

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[8/] "Voluntary Carriage Through 1984", Interstate Natural Gas Association of America, May 1985.

feet or about 16 percent of carriage volumes -- and only 6 percent of total consumption -- was for end-users and distributors. The remaining bulk of the carriage volumes, that is, 5.7 trillion cubic feet, was transported between pipelines and their producer affiliates and for other pipeline shippers.

The Federal Energy Regulatory Commission has now issued a sweeping Notice of Proposed Rulemaking, dated May 30, 1985, which would radically change the natural gas marketplace. NGSA is in the process of preparing its response to the Commission on its proposals and will submit these comments at a later date for inclusion in the record of this hearing.

LEGISLATIVE PROPOSALS

There are currently a number of legislative proposals which have been introduced during this session of Congress concerning natural gas. NGSA has commented on various aspects of several of these proposals.

NGSA generally supports the inclusion and adoption of six legislative principles for a sound and comprehensive natural gas policy. They are: (1) decontrol of natural gas subject to contracts which expire or will expire; (2) decontrol of gas produced through enhanced recovery techniques; (3) equal access by all buyers to all gas supplies; (4) non-discriminatory contract carriage; (5) repeal of certain portions of the Fuel Use Act; and (6) repeal of the incremental pricing provisions of the NGPA.

Only one of the many bills introduced to date, that is, the "Natural Gas Consumer Supply and Marketing Act," HR 2734 introduced by Congressmen Bill Richardson (D-NM) and William Dannemeyer (R-CA), touches on all six principles. NGSA supports in theory the treatment by the Richardson-Dannemeyer legislation of all six principles, but recommends that the following changes be incorporated into the bill's language:

a. That further specificity be given in Title I to describing the contracts and the gas subject to them which would be decontrolled upon expiration of the contracts. For example, the bill should include a provision to deregulate gas subject to life of lease contracts;

b. That the contract carriage obligation be imposed on local distribution companies in Title II and that the provision for LDC bypass be deleted;

c. That contract carriage should not apply to gathering systems;

d. That carriage transportation should not be provided as a trade-off for take-or-pay relief; and

e. That a minimum bill offset provision should be included for the benefit of purchasers whose pipeline supplier has elected to reduce its service obligation.

Even though NGSA favors contract carriage as one of the six principles which it supports, the Association cannot support Senator Bradley's bill, S. 834, as currently drafted for the following reasons:

a. Contract carriage should not be imposed on gathering systems because these facilities are related to the production, not the transportation, of natural gas.

b. Interstate pipelines should not be permitted to abrogate their contractual purchase obligations and take-or-pay obligations to offset reductions in sales due to contract carriage.

c. Available transportation capacity on a firm basis is so defined that most pipelines would not have any space available. The capacity needed to meet the "maximum quantities" of existing customers would likely require the entire capacity of most pipelines. No excess capacity would exist for firm contract carriage.

d. Fully allocated costs are to be used to determine rates of transportation, even interruptible sales. NGSA believes that the Commission should have the flexibility to permit transportation rates at a lower level where required by the market.

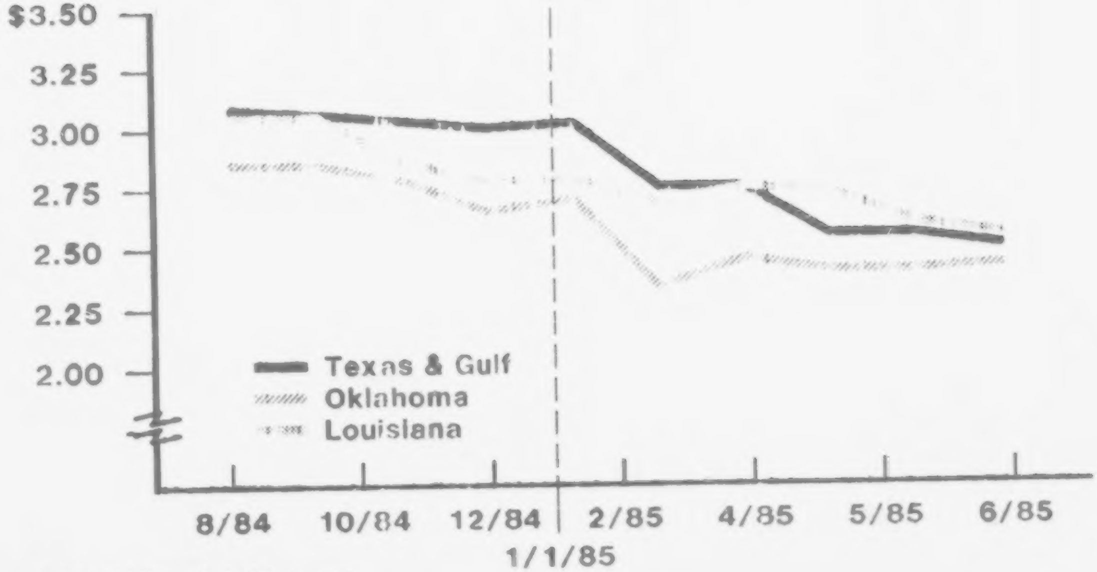
e. No provision is made to require the pipelines to construct minor facilities to implement contract carriage.

f. Contract carriage should be available to any customer of a local distribution company at any time.

NGSA has provided its initial comments on an earlier draft of Senator Nickles' bill, S. 1302. We recommend that if this legislation were to be considered prior to implementation of a non-discriminatory transportation program through a FERC rulemaking that the scope of S. 1302 be expanded to include non-discriminatory contract carriage. At any time, we urge that enhanced recovery and equal access provisions be added to S. 1302. Provision should also be made for the decontrol of all gas subject to life of lease contracts.

ATTACHMENT #1

SPOT MARKET PRICES
(DOLLARS PER MMBTU)

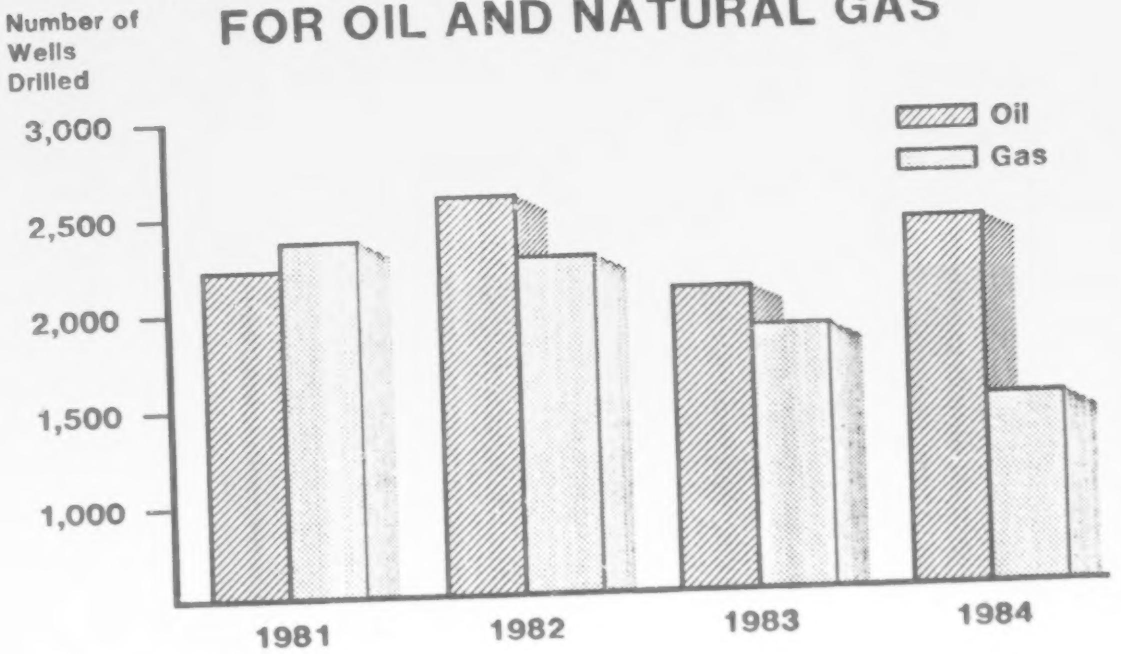


Source: Natural Gas Intelligence

Natural Gas Supply Association

ATTACHMENT #2

EXPLORATORY WELLS DRILLED FOR OIL AND NATURAL GAS

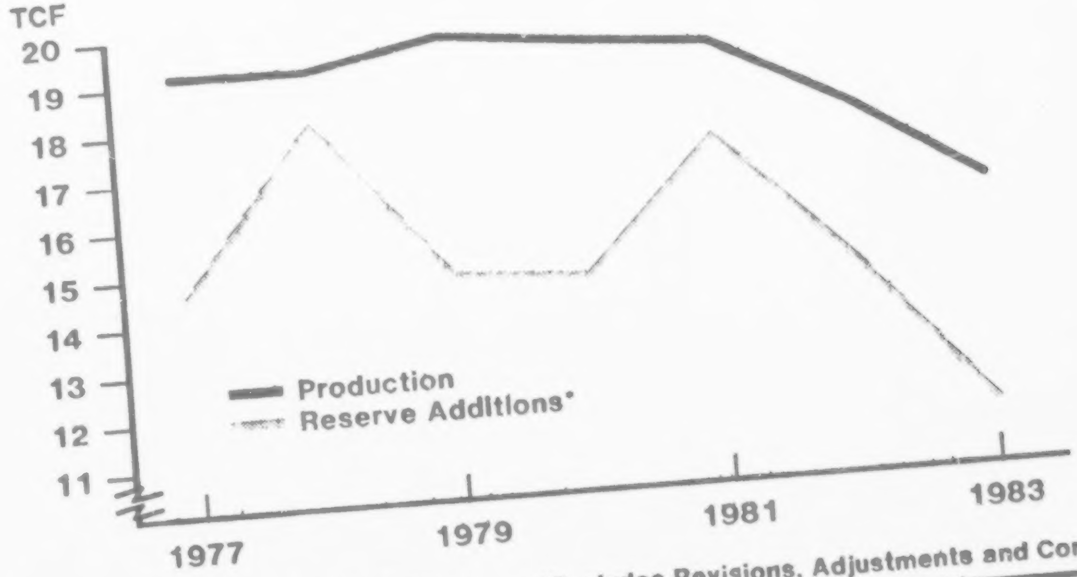


Source: American Petroleum Institute

Natural Gas Supply Association

ATTACHMENT #3

NATURAL GAS RESERVE ADDITIONS AND PRODUCTION



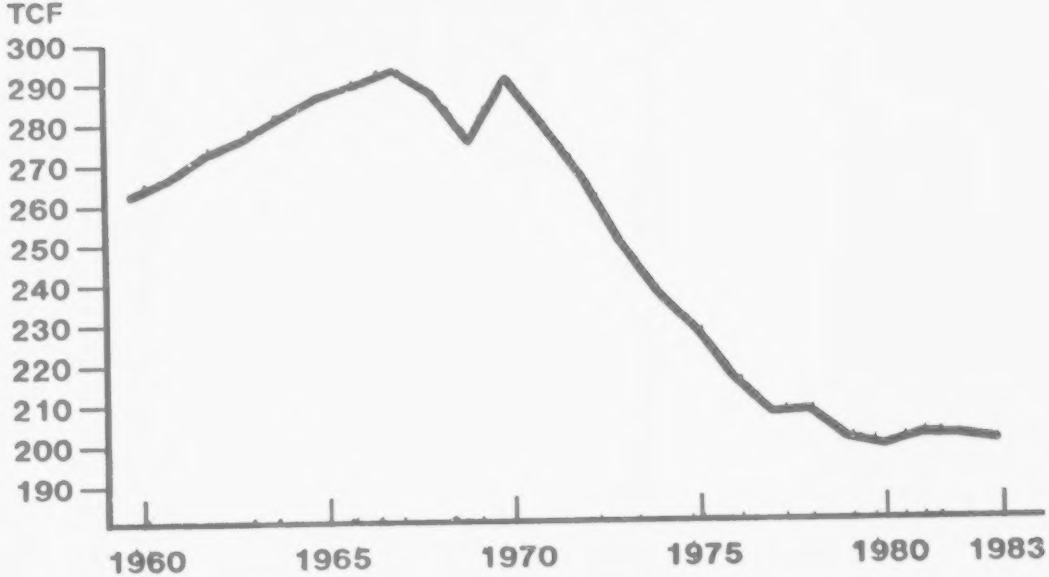
*Excludes Revisions, Adjustments and Corrections

Source: Energy Information Administration

Natural Gas Supply Association

ATTACHMENT #4

PROVED RESERVES OF NATURAL GAS



Sources: American Gas Association, Energy Information Administration

Natural Gas Supply Association

ATTACHMENT #5

COMPARISON OF WEIGHTED AVERAGE PURCHASED GAS COSTS FOR SELECTED PIPELINES 1983-1985

Pipeline	1983 WACOG*	1985 WACOG*	% Change
ANR Pipeline	$3.20	$2.67	-16.6
Columbia Gas Transmission Co.	3.70	3.07	-17.0
Internorth	2.64	2.34	-11.4
MidCon (Natural)	2.55	2.49	- 2.4
Panhandle Eastern	3.26	2.65	-18.7
Tennessee Gas Pipeline	3.21	2.80	-12.8
Texas Eastern	2.84	2.37	-16.5
Transwestern Pipeline Co.	3.27	2.86	-12.5
Trunkline Gas Co.	3.83	2.84	-25.8
Transcontinental Gas Pipeline	3.35	2.99	-10.7
United Gas Pipe Line Co.	3.26	2.86	-12.3

*Dollars Per MMBtu

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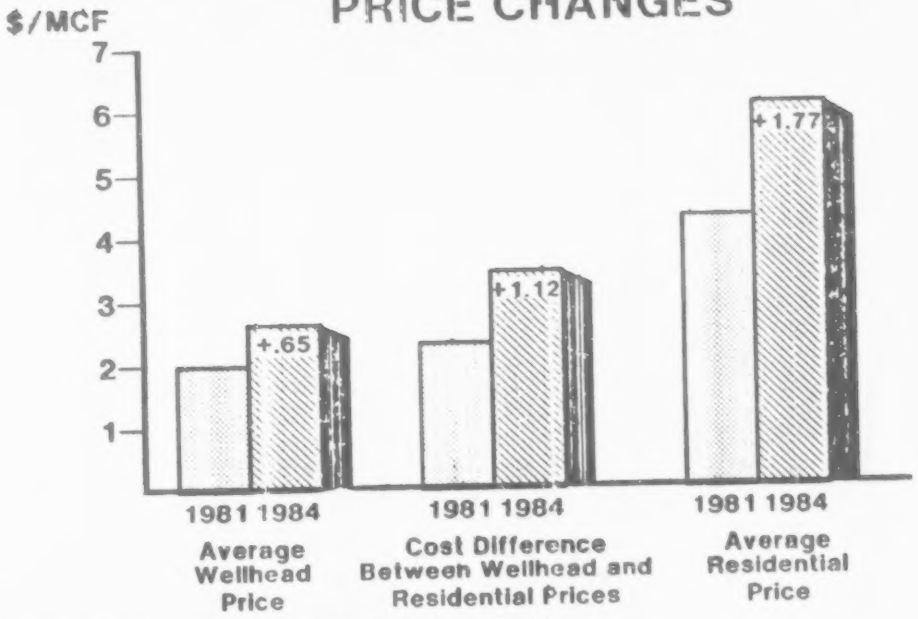
ATTACHMENT #6

COMPARISON OF WELLHEAD AND RESIDENTIAL PRICE CHANGES



Source: DOE/EIA Natural Gas Monthly, February 1985

Natural Gas Supply Association

ATTACHMENT #7

GROWTH IN TOTAL DOWNSTREAM MARGIN

	$/MCF	
	1973	1983
Average Consumer Price*	.79	5.12
Wellhead Price**	.22	2.59
Margin	.57	2.53
MEMO: Margin Adjusted for Inflation Using 1973 Dollars	.57	1.24

*AGA Gas Facts, 1983 Data

**EIA: Natural Gas Monthly, February 1985

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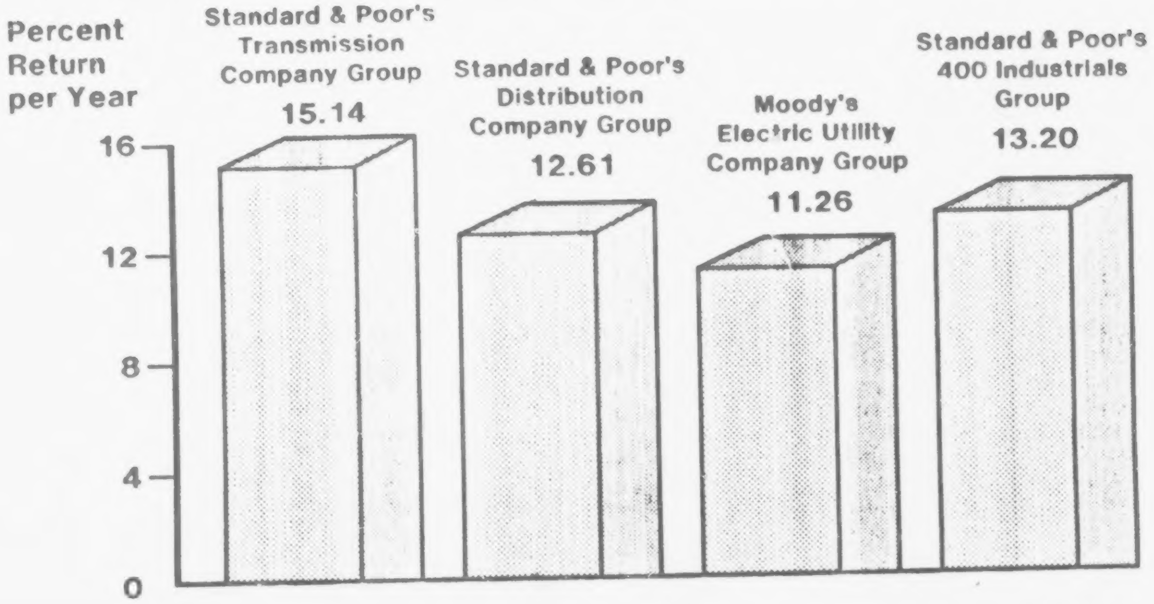
ATTACHMENT #8

AVERAGE RETURN ON EQUITY PERFORMANCE BY COMPANY GROUPING, FROM 1970-1983



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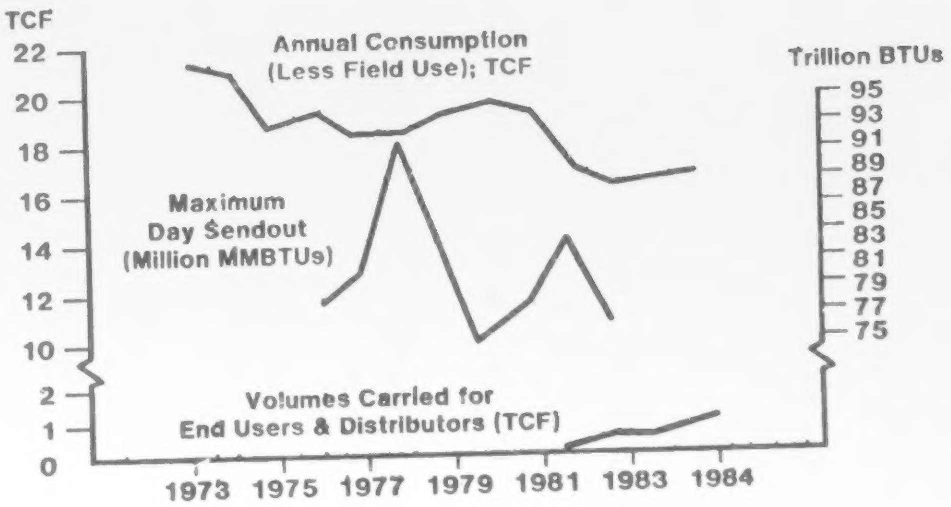
ATTACHMENT #9

TWO MEASURES OF CAPACITY UTILIZATION



Source: Interstate Natural Gas Association of America

1984 DATA
FOR MAXIMUM DAY
SENDOUT... NOT AVAIL

Natural Gas Supply Association

Appendix A

COMPARISON OF NATURAL GAS TRANSMISSION COMPANY RATES OF RETURN AND RISK WITH OTHER REGULATED AND NON-REGULATED INDUSTRIES

Summary

Federal regulation of natural gas transmission companies attempts to balance the requirement of providing consumers with gas at a just and reasonable rate while also insuring the continued financial health of the firm. Financial health is often measured by comparing a firm's net income either to the stockholders equity or to the firm's total debt and equity, commonly known as the return on equity and the return on total capital, respectively. Both measures indicate the relative profitability of an investment. Companies which enjoy high rates of return can readily obtain funds for long-term investments and short-term cash-flow liabilities both of which are crucial to a firm's continued existence.

Federal regulation protects the financial health of natural gas monopolies by designing transportation rates which have a rate of return built into the rate structure. Because of the financial protection afforded by Federal regulation, the question has been raised as to the real risks faced by a pipeline and the rate of return appropriate to the level of risk assumed by pipeline firms.

This analysis examined the historical returns to equity and capital as experienced by the following company groupings:

- Natural Gas Transmission Companies
- Natural Gas Distribution Companies
- Electric Utilities/All Regulated Utilities
- All Industrial Companies

One measure of investment risk which is used in this analysis is the degree to which the rate of return varies from one year to the next. A high degree of variation in return would lower an investor's confidence in obtaining the average historical real rate of return and thereby make the investment a higher risk investment. Rate of return variability is measured through the standard deviation of the statistic.

Alternative sources were employed to create return on equity and return on capital statistics. Statistics of company groupings were obtained primarily from the 1984 editions of the Standard and Poor Analysts Handbook, and the Moody Public Utility Manual. Because transmission company group composites reflect the parent company's financial status and not just the natural gas pipeline segment of the business, an alternative statistical series was developed from the FERC Form 2 which reports only pipeline operations. Similarly, an alternative series was developed for distribution companies by using individual company data in Moody's for firms which are strictly gas distribution firms. Irrespective of the measure used (i.e. return on equity vs. return on capital), and the source for that measure, the following results remain generally true:

1. Natural gas transmission companies receive the highest return of any company grouping.

2. Natural gas transmission companies experienced the lowest degree of risk in terms of the variability measured here when compared to other company groupings.

3. Transmission company returns have been protected from the adverse consequences of high inflation by federal regulation.

Analytical Design

Many approaches can be taken in developing industry composites for rates of return. Alternative composites can be created by selecting different companies for inclusion, by specifying alternative measurement rules, and by defining the historical period. The analysis primarily relied upon company grouping statistics reported in the 1984 editions of the Standard and Poor Analysts Handbook and Moody Public Utility Manual. These data sources permitted the construction of data series spanning 1970 through 1984. This fourteen year series captures both the market disruptions caused by local gas shortages in the mid to late 1970's and the more recent pipeline financial difficulties caused by contract take-or-pay provisions. Consequently, this historical period encompasses a time when pipeline returns could have been seriously imperiled and subject to wide swings.

The Moody Public Utility Manual directly reports return on equity for gas transmission, gas distribution, and electric utilities. The Standard and Poor's return on equity for the industrial 400 is equated with the percent return on book value. The Standard and Poor statistics for return on capital were equated with the percentage earned on net property. The Standard and Poor return on capital statistics for 40 utilites represents a composite of the largest electric, natural gas distribution, natural gas pipeline, and telephone companies.

One drawback exists in using these statistics because they reflect parent company returns and not just the returns of the pipeline business within the parent. To overcome this deficiency, FERC Form 2 information was used to develop return series for transmission companies. Specifically, the Department of Energy publication entitled "Statistics of Interstate Natural Gas Pipeline Companies" was the data source with composite statistics for Major Class A and B Pipeline Companies used as representing transmission companies. Although this approach removes the bias inherent in using parent company statistics, the companies that are classified as Major Class A and B Pipeline Companies changes from year to year. However, this should not cause significant bias because it is the small pipelines that enter and leave this category. The large transmission companies are consistently retained in this category and they represent the bulk of the earnings and assets.

The American Petroleum Institute prepared the FERC Form 2 transmission company returns for 1975 through 1983 along with a series developed for distribution companies[1/]. The distribution company returns were developed from individual company data obtained from the Moody Public Utility Manual. The distribution company sample is comprised of 14 companies which are listed in Exhibit VI. The companies included in the sample were identified from a list comprised of large gas utilities plus others included in a Forbes magazine distribution company sample. Combination gas and electric companies and subsidiary companies for which unconsolidated financial data are not publicly available were eliminated. Of the remaining companies, only those whose revenues from sales to ultimate consumers accounted for more than half of total operating revenue were retained in the sample. For the companies retained, average revenues from residential, commercial and industrial sales accounted for more than 75% of average total operating revenue.

Using both FERC Form 2 and the Moody Public Utility Manual respectively for transmission and distribution firms, API calculated the stockholder's return on equity by using aggregate figures and by dividing each year's net income by the average of beginning and end of year stockholder's equity. Similarly, return on total capital was estimated using aggregate statistics and is defined as net income plus after-tax interest expense for the year divided by the average of beginning and end of year stockholder's equity and long-term debt.

[1/] American Petroleum Institute correspondence from Dr. Leonard Bower to Mr. Steve Bojack of Standard Oil Company (Indiana), dated June 4, 1984.

Discussion Of Results

Exhibits I through IV display both the data and illustrate the relationship between a company group average rate of return and standard deviation. Exhibits I and II contain return on equity statistics, while Exhibits III and IV report return on total capital figures.

When the raw statistics are used to calculate the average return and its standard deviation, the transmission companies show both the highest returns and the largest standard deviation. However, when the impacts of inflation are removed by substracting the rate of increase in the Implicit GNP Price Deflator, the real rate of return remains the highest for transmission companies while its standard deviation becomes the lowest relative to the other company groupings although the differences may not be statistically significant because of the small sample sizes. The higher nominal rate of return variance for transmission companies may be due to Federal regulatory efforts to achieve a stable real rate of return.

As a result, gas transmission companies have enjoyed higher rates of return at a lower risk (i.e., a low standard deviation in returns) than the domestic industrial base. In the marketplace, a firm with a low yet stable rate of return is given equal investment preference as a firm with a high but highly variable rate of return. Yet regulatory economics is perversely at odds with marketplace economics.

Real Gross National Product growth measures the increase in national wealth. Theoretically, real returns to capital can be no larger than GNP growth without causing a redistribution of wealth. In other words, compensation to investment can only grow as quickly as real national income. Because the size of the economic pie is infinite if investment compensation grows faster than GNP, then non-investment compensation, such as real wages, must diminish. For example, between 1975 and 1983 real GNP grew at 2.79% per year which is very close to the total returns to capital experienced by industry which amounted to 2.80% per year. Transmission company returns to capital, however, averaged just over 4 percent per year. Under these circumstances a redistribution of wealth occurred, with wealth flowing to pipeline investors.

Conclusions

Historical methods of regulating pipeline rates of return have produced higher than marketplace rates of return, have protected these high rates from risk, and result in a de facto policy of wealth redistribution to pipeline stockholders. Although Federal regulation was meant to protect consumers and producers from monopolistic practices, regulations have, in fact, protected pipeline monopolies from experiencing marketplace economies, where rates of return are not commensurate with the level of investment risk. Instead, Federal regulation has guaranteed high rates of return for low risk investments. It would appear more reasonable that as long as Federal regulation can insure a stable real rate of return, the average rate of return should be decreased to be less than that of the industrial sector and equivalent to the returns obtained by other regulated industries.

Exhibit I

RETURN ON EQUITY BY COMPANY GROUPING
(Percent)

RAW STATISTICS

	Transmission Cos.		Distribution Cos.		Electric Utilities	All Industries
	Standard & Poor's	FERC Form 2	Standard & Poors	Moody's Public Utility Manual	Moody's Public Utility Manual	Standard & Poor's 400
1970	12.3		12.8		10.8	10.28
1971	13.6		12.3		10.8	10.80
1972	12.7		12.6		11.0	11.71
1973	13.2		11.5		10.5	14.15
1974	15.2		11.9		10.4	14.17
1975	14.7	15.1	11.5	12.6	10.3	12.11
1976	15.6	15.7	12.6	12.5	10.6	14.02
1977	15.9	15.6	13.6	13.9	11.0	13.93
1978	15.5	15.1	15.2	13.5	10.7	14.60
1979	17.7	17.1	14.2	14.2	11.0	16.50
1980	19.0	16.8	13.2	12.9	10.7	14.88
1981	19.2	18.0	13.4	15.0	12.4	14.42
1982	15.7	15.3	11.0	13.9	13.2	11.13
1983	11.7	13.3	10.7	12.2	14.3	12.15
Average Value	15.14	15.78	12.61	13.41	11.26	13.20
Standard Deviation	2.34	1.37	1.26	0.93	1.18	1.82

NET OF INFLATION[1]

	Transmission Cos.		Distribution Cos.		Electric Utilities	All Industries
	Standard & Poor's	FERC Form 2	Standard & Poors	Moody's Public Utility Manual	Moody's Public Utility Manual	Standard & Poor's 400
1970	6.93		7.43		5.43	4.91
1971	8.61		7.31		5.81	5.81
1972	8.54		8.44		6.84	7.55
1973	7.45		5.75		4.75	8.40
1974	6.38		3.08		1.58	5.35
1975	5.39	5.79	2.19	3.29	0.99	2.80
1976	10.39	10.49	7.39	7.29	5.39	8.81
1977	10.07	9.77	7.77	8.07	5.17	8.10
1978	8.10	7.70	7.80	6.10	3.30	7.20
1979	9.06	8.46	5.56	5.56	2.36	7.86
1980	9.82	7.62	4.02	3.72	1.52	5.70
1981	9.57	8.37	3.77	5.37	2.77	4.79
1982	9.68	9.28	4.98	7.88	7.18	5.11
1983	7.86	9.46	6.86	8.36	10.46	8.31
Average Value	8.42	8.55	5.88	6.18	4.54	6.48
Standard Deviation	1.49	1.41	2.00	1.87	2.64	1.79

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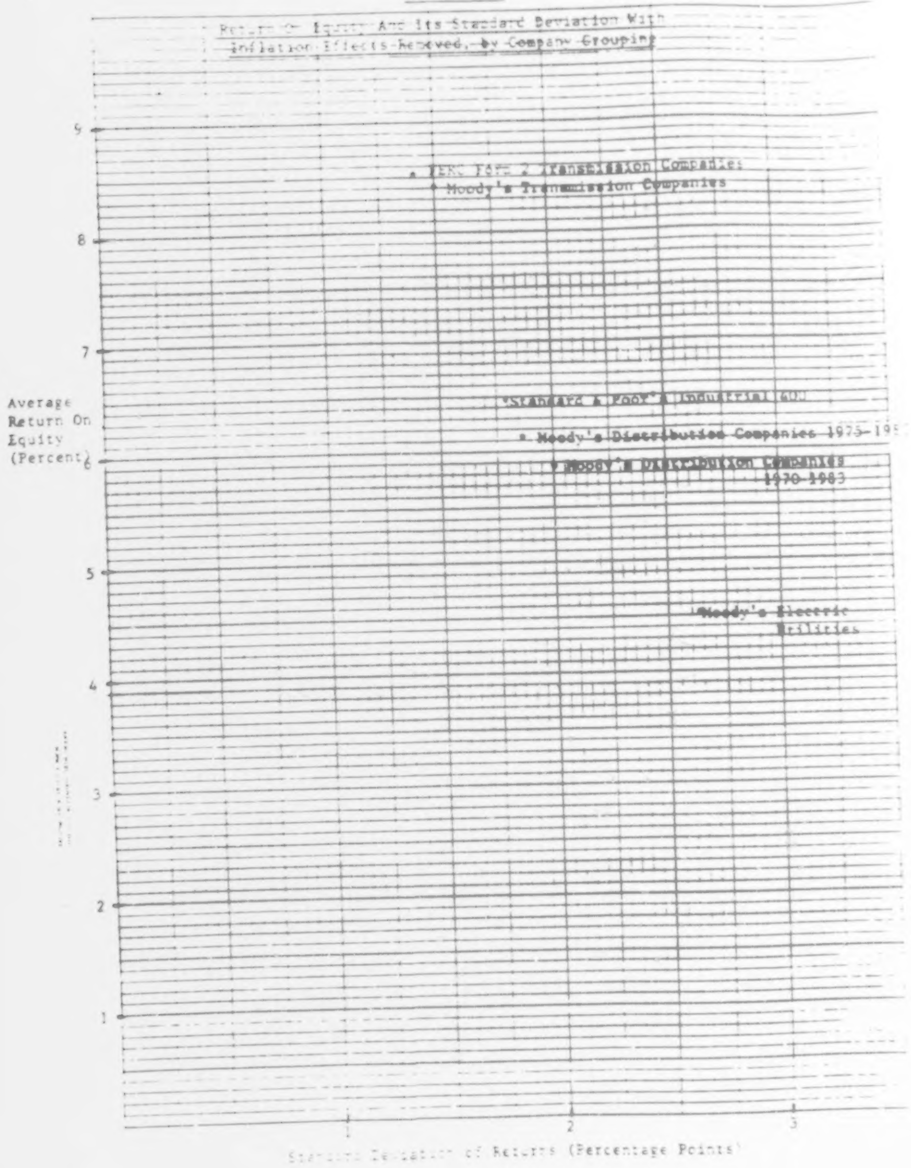
[1] Raw statistics minus the rate of change in the Implicit GNP Price Deflator, as given in Exhibit V.

Exhibit II



Return On Equity And Its Standard Deviation With Inflation Effects Removed, by Company Grouping

Exhibit III

RETURN ON TOTAL CAPITAL BY COMPANY GROUPING
(Percent)

RAW STATISTICS

	Transmission Cos.		Distribution Cos.		Standard & Poor's 40 Utilities
	Standard & Poor's	FERC Form 2	Standard & Poors	Moody's Public Utility Manual	
1970	7.78		7.20		6.39
1971	8.64		7.66		6.40
1972	9.18		7.89		6.58
1973	9.32		7.97		6.63
1974	9.06		8.82		6.89
1975	8.69	9.7	8.90	8.2	7.12
1976	8.74	10.1	9.59	8.1	7.18
1977	10.39	10.4	9.67	8.9	7.20
1978	10.34	10.5	9.18	8.9	7.34
1979	9.84	12.2	9.56	9.7	7.33
1980	10.87	12.5	9.66	9.5	7.93
1981	10.78	13.5	10.49	11.0	8.21
1982	9.61	11.9	10.05	10.4	8.46
1983	9.80	10.7	10.07	9.3	8.57
Average Value	9.50	11.28	9.05	9.33	7.30
Standard Deviation	0.90	1.29	1.01	0.95	0.73

NET OF INFLATION[1/]

	Transmission Cos.		Distribution Cos.		Standard & Poor's 40 Utilities
	Standard & Poor's	FERC Form 2	Standard & Poors	Moody's Public Utility Manual	
1970	2.41		1.83		1.02
1971	3.65		2.67		1.41
1972	5.02		3.73		2.42
1973	3.57		2.22		0.88
1974	0.24		0.00		- 1.93
1975	- 0.62	0.39	- 0.41	- 1.11	- 2.19
1976	3.53	4.89	4.38	2.89	1.97
1977	4.56	4.57	3.84	3.07	1.37
1978	2.94	3.10	1.78	1.50	- 0.06
1979	1.20	3.56	0.92	1.06	- 1.31
1980	1.69	3.32	0.48	0.32	- 1.25
1981	1.15	3.87	0.86	1.37	- 1.42
1982	3.59	5.88	4.03	4.38	2.44
1983	5.96	6.86	6.23	5.46	4.73
Average Value	2.78	4.05	2.33	2.10	0.58
Standard Deviation	1.87	1.85	1.92	2.05	2.02

[1/] Raw Statistics minus the rate of change in the Implicit GNP Price Deflator, as given in Exhibit V.

Exhibit IV

Return On Capital And Its Standard Deviation

With Inflation Effects Removed, By Company Grouping

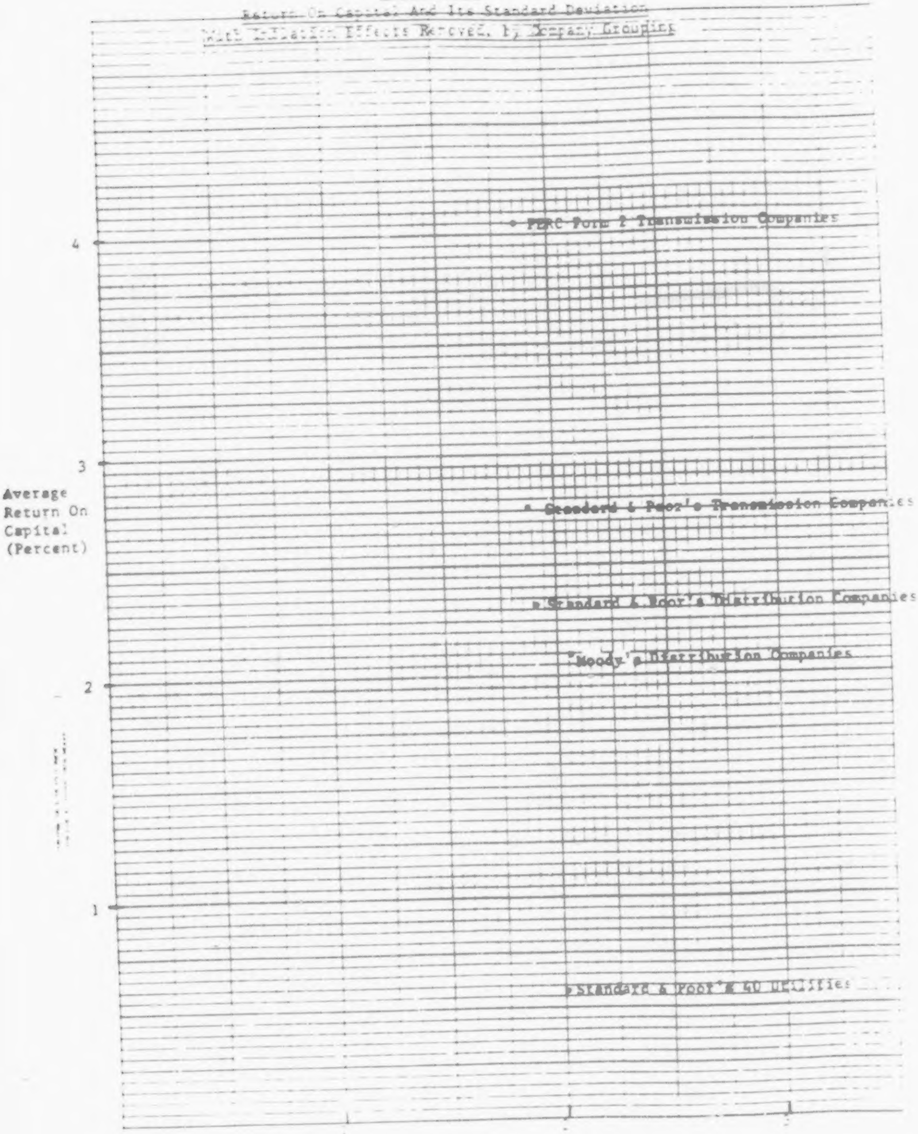


Exhibit V

GNP IMPLICIT PRICE DEFLATOR HISTORICAL GROWTH RATES
(Percent Per Year)

1970	5.37
1971	4.99
1972	4.16
1973	5.75
1974	8.82
1975	9.31
1976	5.21
1977	5.83
1978	7.40
1979	8.64
1980	9.18
1981	9.63
1982	6.02
1983	3.84

Source: U.S. Department of Commerce, Bureau of Economic Statistics

Exhibit VI

NATURAL GAS DISTRIBUTION COMPANY SAMPLE FOR 1975 THROUGH 1983 DATA SERIES

Arkla, Incorporated
East Ohio Gas
Southern California Gas Company
Northern Illinois
Michigan Consolidated Gas Company
People's Gas, Light and Coke
Oklahoma Natural
National Fuel Gas Company
Brooklyn Union
Southern Union
Laclede Gas
Atlanta Gas Light
Gas Service Company
KN Energy, Incorporated

Senator NICKLES. Thank you very much.
Mr. McGrath.

STATEMENT OF JEROME J. McGRATH, PRESIDENT, INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

Mr. McGRATH. Mr. Chairman, I am Jerome McGrath, president of Interstate Natural Gas Association of America. I appreciate greatly the opportunity to appear before you today.

Since my written statement will be included in the record, I will summarize the main points of it.

Senator NICKLES. Thank you.

Mr. McGRATH. INGAA represents, as you know, Mr. Chairman, virtually all of the major interstate natural gas pipeline companies. Over 90 percent of the natural gas transported in interstate commerce flows through the pipelines of INGAA member companies.

First, I would want to address the market conditions facing the industry today and then turn to the notice of proposed rulemaking recently issued by the Federal Energy Regulatory Commission.

The natural gas industry, as you and I'm sure all the members of the subcommittee know, has been in turbulence for the last 2½ years. We have been confronted with surplus deliverability, declining oil prices, reduced gas demand, high wellhead prices, and onerous take-or-pay obligations.

The interstate pipelines have responded by lowering prices, where possible, and by expanding excess to their transportation networks. Examples of such efforts include the renegotiation of Canadian import agreements, the exercise of market-out clauses, where they exist, special marketing programs and the like.

Unfortunately, we have been unable to bring all prices for gas down to market responsive levels. Prices for deep gas, for example, and for many regulated categories of gas remain well above market clearing levels, and producers have been reluctant to renegotiate these prices.

Although price renegotiation has been less than we would like, the pipelines have made some progress in reducing their take-or-pay obligations. Pipelines have also made substantial progress in transporting gas for others.

In 1984, volumes transported for distributors and end users increased by some 65 percent over 1983. The trend continued during the first quarter of 1985, with volumes up 36 percent from the first quarter of 1984.

In spite of these gains, our industry is often accused of refusing to transport gas for others. Of course, pipelines have not been able to provide transportation in every case, but our data indicate that there were more than 1,800 successful transportation arrangements for nonpipeline shippers in 1984, and almost 1,000 transactions in the first quarter of 1985 alone.

Clearly, pipelines have been making progress toward a more open transportation network, but we may never know how successful we would have been in completing the transition because of the recent court of appeals decision and the Commission's notice of proposed rulemaking.

Through its notice of proposed rulemaking, the Commission has undertaken a radical restructuring of the interstate natural gas pipeline industry.

Although we support the Commission's overall objective of "insuring that consumers are provided the lowest reasonable rates consistent with reliable, long-term service," the proposal requires modification and clarification to meet its objective and to have a legally sustainable rule.

The NOPR, as they're calling it these days, leaves unresolved technical and procedural details too numerous for me to mention here. I will focus, therefore, on the main concerns we have with the proposal.

First, INGAA opposes the proposed departure from the traditional practice of rolled-in pricing.

Under the block billing procedure, low-cost gas would be considered block 1 and allocated among historical firm service customers, while pipelines would have only block 2 gas with which to compete.

We estimate average block 2 prices, and this is a national average, for pipelines to be about $4 per MMBtu, and most of this gas is bought under contracts with high take-or-pay obligations and prices that are not responsive to market conditions.

With spot market prices ranging from $2.50 to $2.70 per MMBtu, pipelines are faced with the prospect of losing sales not only to existing customers, but also to new markets.

Rather than creating a level playing field, as the Commission so frequently alluded to in its notice, the billing proposal severely disadvantages interstate pipelines.

Two, we do not believe the Commission's proposed take-or-pay buy-out or safe harbor policy will work because it is unlikely pipelines could finance the buy-out payments and because no incentive is provided for producers to renegotiate.

To make the proposal meaningful, the Commission should require producers to voluntarily renegotiate contracts with regard to take or pay before gaining access to pipeline transportation.

Three, with respect to the self-implementing transportation program, many practical and legal questions must be resolved involving matters such as unilateral abandonment, customers' rights to transportation capacity, reservation charges, allocation and recovery of fixed costs, and the allocation of old gas.

Four, finally, much uncertainty is created by the NOPR because of the numerous technical and procedural details left unresolved by the Commission.

Contributing to this uncertainty is the high probability that litigation would begin as soon as a proposal is implemented because of the numerous and considerable legal questions the proposals raise.

INGAA and its member companies are vitally interested in working with the Commission to assure a final rule that will achieve the objective set forth in the NOPR, but that will be within the bounds of sound pipeline operation.

It is also critical that any final rule not inhibit the interstate pipelines from competing for markets on equal terms with the other segments of the industry.

Concerning the legislation pending before this subcommittee, Mr. Chairman, I would repeat our long-standing support for repeal of incremental pricing and the Fuel Use Act.

Because of the uncertainties brought about by the NOPR, INGAA has not yet been able to assess the impact that the further deregulation of wellhead prices, as proposed in S. 1302, will have on the industry.

Finally, we continue to oppose legislation that would impose mandatory contract carriage.

Mr. Chairman, that concludes my statement, and I would be pleased to answer any questions you might have.

[The prepared statement of Mr. McGrath follows:]

STATEMENT OF
JEROME J. MCGRATH, PRESIDENT
INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
JULY 11, 1985

Mr. Chairman and Members of the Subcommittee:

I am Jerome J. McGrath, President, Interstate Natural Gas Association of America (INGAA). I appreciate the opportunity to appear before you today. I will initially comment on proposed natural gas legislation, and follow with a report on the progress interstate pipelines have made in adjusting to competition. The balance of my comments will focus on the Federal Energy Regulatory Commission's (Commission's) Notice of Proposed Rulemaking of May 30, 1985, RM85-1-000, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol (NOPR).

INGAA is a non-profit national trade association representing virtually all of the major interstate natural gas transmission companies operating in the United States. Our member companies move natural gas from the producing areas to distributors and end users located across the nation. The distributors, in turn, sell the gas to the ultimate consumer. Approximately, 90 percent of the natural gas transported and sold annually in interstate commerce flows through the more than 200,000 miles of pipeline owned and operated by INGAA's member companies.

Mr. Chairman, as the Subcommittee knows, the natural gas industry has been in turbulence for the last two and one-half years or more, with major changes taking place daily. Confronted with surplus in deliverability, declining oil prices and reduced gas demand on the one hand and high wellhead prices and onerous take-or-pay obligations on the other, interstate natural gas pipelines have become more competitive by lowering prices and by expanding access to their transportation network. Notwithstanding the pipelines' transition toward a more competitive environment, the pipelines are now faced with major regulatory reform.

PROPOSED NATURAL GAS LEGISLATION

Regarding proposed natural gas legislation, Mr. Chairman, we would like to voice our support for your efforts and those of the sponsors of S.1251 to repeal incremental pricing and end-use restrictions on natural gas. These artificial barriers to gas sales are anachronisms from a time when a rapidly dwindling supply of gas was foreseen. In fact, these restrictions are stumbling blocks to the functioning of gas markets and they should be repealed. Because of the uncertainties brought about by the NOPR, INGAA has not been able to assess the impact that the further deregulation of wellhead prices as proposed in S.1302 will have upon the industry. With respect to legislative proposals such as S.834, INGAA believes that mandatory carriage is both unnecessary and unwise and we would oppose its inclusion in any bill.

PIPELINE MARKET TRANSITION

I would like to elaborate on the progress interstate pipelines have made in meeting the challenges of the marketplace. The interstate pipelines have been making the transition to a competitive market environment by working to lower prices, reduce take-or-pay liabilities and voluntarily transport substantial volumes of gas for others. As reported by Deputy Energy Secretary Boggs when he appeared before this Subcommittee on June 18, 1985, gas prices have declined slightly. This has resulted in part from the softening of the oil and gas markets and efforts by pipelines to respond to these market forces. Examples of such efforts are the renegotiation of Canadian import agreements and reductions in prices through the exercise of market-out provisions. Nevertheless, prices for "deep" gas and for many regulated categories remain well above market clearing levels and producers have been reluctant to renegotiate these prices.

From 1982 to 1985, the average prices paid for deep gas declined from about $7.40 to about $5.00 per MMBtu. This decline is primarily attributable to pipelines exercising market-out clauses in their gas purchase contracts. In spite of this decline, the average price is still almost twice current spot market prices, which range from $2.50 to $2.70 per MMBtu.

At present, the maximum lawful prices (MLPs) under the Natural Gas Policy Act (NGPA) for Section 102(d), 103(b)(1), 103(b)(2), 108 and 107 tight-sand gas range from a low of $3.00 to a high of $6.01 per MMBtu. These regulated prices exceed the pipelines' average purchased gas costs, their market-out prices and recent spot market prices. The average purchased gas cost for 65 percent of the interstate market is below $3.00 per MMBtu, with 95 percent below $3.50. Data for some 75 percent of the market show that pipeline market-out prices are below $3.50 per MMBtu. Therefore, the maximum lawful prices for these regulated gas categories are too high. But since actual average prices paid for these categories of gas are essentially equal to the MLPs, it is obvious that contracts for these regulated categories of gas have not been renegotiated to lower price levels.

The pipelines have little leverage to accomplish the needed price renegotiation for at least two reasons. First, the NGPA deems that when prices paid for gas do not exceed the appropriate MLP, the price shall be considered just and reasonable. Second, the pipeline can lawfully pass through these costs to its customers. Given these facts, it is generally difficult for a pipeline to persuade a producer to voluntarily reduce its gas prices. The Commission's NOPR, as I will point out later, would not provide any additional incentives for the producers to renegotiate high-priced contracts.

Although price renegotiation with domestic producers has been less than we would like, the pipelines have made some progress in obtaining relief from and in reducing their take-or-pay obligations. Through 1984, two interstate pipelines alone reported they were able to reduce their take-or-pay obligations by a total of almost $3 billion. While some producers have been willing to permanently reduce take-or-pay prepayments and/or take-or-pay levels, others have provided short-term relief in hopes of better days ahead. The Commission's current procedures for treating one-time lump sum buyouts of problem contracts have also been helpful to pipelines in dealing with the take-or-pay problem. Additionally, the pipelines have been permitted either to earn on their take-or-pay prepayment investments or at least recover carrying costs on the prepayments. Much more remains to be done, however, with extant problem contracts.

In an effort to make the transition to a more competitive marketplace, the pipelines have made substantial progress in transporting gas for others. Voluntary carriage has always been an important part of the interstate pipelines' business, and increasingly so in the last ten years. Reflecting this activity is the rapidly expanding voluntary carriage service for distributors and end users. In 1984, transportation for distributors and end-users represented about ten percent of the sales in the interstate market. Volumes transported for distributors and end-users increased by some 65 percent to a total of 1099 billion cubic feet (bcf) from 666 bcf in 1983. The trend to increased voluntary carriage continued with 320 bcf transported during the first quarter of 1985, up 36 percent from the first quarter in 1984. This increase in carriage for distributors and end users offset a 20 percent decrease in carriage for other pipelines over the same period. These trends are indicative of the progress pipelines have made in transporting gas for shippers other than pipelines.

In spite of these gains, interstate pipelines have been accused of refusing to transport gas for others. Although it is true that pipelines have not been able to provide transportation service under all circumstances, pipelines representing about 75 percent of the interstate market provided more than 1800 successful transportation arrangements for shippers other than pipelines in 1984 and almost another 1000 transactions in the first three months of 1985. In those situations where transportation service was not provided, it was primarily because the transportation volumes would have displaced the pipeline's sales, thereby exacerbating its take-or-pay problems, or sufficient capacity was not available. These transportation figures clearly indicate that the pipelines have been making progress toward a more open transportation network. However, we may never know how successful the pipelines would have been in completing the transition because of a recent Court of Appeals decision and the Commission's NOPR.

COMMISSION'S NOTICE OF PROPOSED RULEMAKING

The NOPR if adopted by the Commission would bring about a major restructuring of how business is conducted in the natural gas industry. INGAA concurs with the Commission's overall goal of ensuring that "consumers are provided the lowest, reasonable rates consistent with reliable, long-term service." While we are not defending the status quo, INGAA doubts that the drastic restructuring of the industry as proposed in the rulemaking would meet the Commission's intended objective. Our basic concerns fall into four areas:

1. The Commission's proposed policies do not adequately substantiate such a major change from over forty years of regulatory, statutory and judicial history that form the foundation for the pipelines' service obligations and certificates of public convenience and necessity. This is especially true of the proposed replacement of rolled-in pricing with block pricing. Even if this change can be justified, block pricing should not be structured in a way that would hinder the sale of competitively priced gas.
2. The Commission's proposed programs would be ineffective unless adequate take-or-pay relief is provided. The proposed take-or-pay relief will not work because it is unlikely pipelines could finance the buyout payments and because no incentive is provided for producers to renegotiate.
3. The Commission's Notice, as it pertains to self-implementing transportation, gives inadequate recognition to service obligations and long-term supply upon which pipeline systems have been designed. This is exemplified in part by the proposed right of historical sales customers to abandon sales service and convert to transportation service.
4. Considered as a whole, the Commission's proposed rulemaking leaves numerous technical and procedural details unresolved and creates considerable legal questions that are likely to be disruptive to the successful implementation of the proposal.

Although we have these concerns about the appropriateness and effectiveness of the Commission's NOPR, INGAA hopes to be able to work with the Commission to modify the program being proposed. To this end, we are in the process of preparing comments in response to the Commission's Notice in which we will recommend changes to the NOPR that we believe enhance its workability.

Mandated Billing Procedure

The Commission proposes three significant changes to pipeline billing procedures:

1) Three-part billing, which is a departure from forty years of rolled-in pricing,
2) Block 2 prices would be presumed prudent after four years, which is de facto deregulation of this gas, and
3) Allocation of "old" gas to existing firm customers, which is a departure from the historical system supply treatment.

In the three-part billing system, block 1 would contain a pipeline's low-priced gas (about 50 percent of interstate sales), block 2 would contain all other gas costs (about 50 percent of interstate sales) and block 3 would contain yet to be specified other costs.

Under current conditions the average cost of old gas, which would be included in block 1, is estimated to be $1.65 per MMBtu. In contrast, block 2 prices are estimated to average $4.00 per MMBtu. With spot market prices ranging from $2.50 to $2.70 per MMBtu, clearly the average block 2 gas would be unmarketable. About 65 percent of block 2 purchases would be bought under contracts that have high take-or-pay obligations and prices that are not responsive to market conditions. With this reality, pipelines are faced with the prospect of losing sales not only to existing customers but also to new markets.

In addition to disadvantaging the pipelines, the proposed billing procedure penalizes those producers who have been willing to enter into or renegotiate market responsive contracts, because their gas sales would be hindered by the high-priced gas also included in block 2. Moreover, the proposed billing procedure does not communicate accurate price signals for the development of new supplies since pipelines would have to buy new gas at below market clearing levels if block 2 is to become competitively priced. Thus, market signals would be distorted and the playing field tilted against the pipelines.

INGAA continues to support rolled-in pricing but assuming the Com- mission adopts block billing, an alternative structure to the three-part billing system would be to separate gas bought under market responsive con- tracts from the other gas in block 2 so that pipelines could use the market responsive gas to compete on a level playing field. This could be done by either subdividing block 2 or creating an additional block.

Take-or-Pay Relief

Even if the block pricing is modified as we recommend, effective take-or-pay relief must be provided if the pipelines are to be given an equal opportunity to compete and if all producers are to share in the risks. The Commission attempts to address the block 2 marketability problem by proposing a take-or-pay buyout, "safe harbor" program. The pipelines can buy out contracts with take-or-pay provisions when they can afford it and when the producers are willing to grant relief. Under the proposed safe harbor, the cost of the buyout payments would be extremely high for the pipelines because 1) the safe harbor is so restrictive that the pipelines would be able to recover only a small portion of the payments needed to extinguish future take-or-pay obligations; 2) the pipelines will not be allowed to recover any carrying costs incurred over the five-year amortization period and; 3) the pipelines will not be allowed to earn on the investment required to buy out of the contracts.

Even when a pipeline can afford to buy out its problem contracts and can finance the investment, there is little incentive for the producers to renegotiate. The producer is likely to find that the value of its existing high-price, high-take contracts far exceeds the value of any limited safe harbor buyout. That is, low takes at high prices plus take-or-pay payments are likely to provide more revenue for the producer than higher takes at low prices and a meager buyout payment.

Aside from the problem of perhaps having neither a willing buyer nor a willing seller, the proposed buyout formula establishes ceilings that are certain to become floors that would further impede negotiations with producers and further reduce the usefulness of the proposal. In short, the proposed safe harbor offers little take-or-pay relief. The Commission is correct, however, in seeing take-or-pay relief as being critical for the proposed rulemaking to become a workable program because take-or-pay liabilities can be expected to increase dramatically if block ? remains unmarketable.

INGAA recommends creating an incentive for the producers to provide take-or-pay relief by having the Commission condition producer access to pipeline transportation on producers voluntarily renegotiating contracts that require pipelines to take or pay for gas priced above market clearing levels. This condition would be applicable once a pipeline has held itself out to be a transporter under the self-implementing transportation program.

Self-Implementing Transportation Program

Our understanding of the self-implementing transportation program is that each pipeline will be given a one-time opportunity to elect to be a transporter and to set aside a specific portion of its capacity for transportation. We understand that a pipeline must decide to become a transporter before the "window" closes January 1, 1986, after which it is locked into the capacity dedicated to transportation service forevermore. Thus, if the pipeline overestimates its transportation throughput volume and loses money, it has no opportunity to reduce its transportation volume and adjust its rates accordingly.

Further, the arbitrary right of a customer to reduce its contract demand quantity by 25 percent per year, which can be as much as 50 percent after the first two months of the program, raises many unanswered questions regarding unilateral abandonment, customers' rights to transportation capacity, reservation charges, allocation and recovery of fixed costs, and operational planning.

We believe that a customer should be required to relinquish a proportionate share of its allocation of old gas when it reduces its contract demand. Such a modification would help prevent the ambiguous situation created by the NOPR whereby a customer could completely eliminate its contract demand but retain its allocation of old gas from the pipeline.

Potential for Uncertainty and Litigation

Much uncertainty is created by the NOPR because of the numerous technical and procedural details left unresolved by the Commission. The rulemaking is such a radical change from current regulations that these problems must be solved prior to implementation of any final rule. Otherwise, the rule would totally disrupt the pipelines' operations and planning and create uncertainty throughout the natural gas industry.

Contributing to this uncertainty in planning and directing a pipeline's business is the high probability that litigation would begin as soon as the proposal is implemented because of the numerous and considerable legal questions the proposal raises. The apparent lack of consideration for long-term service obligations, certificates of public convenience and necessity, and more than forty years of regulatory, judicial and statutory history lead to troublesome legal questions relating to such matters as the Commission's authority to:

1) abandon rolled-in pricing without a finding, based on an adequate record, that rolled-in pricing is no longer just and reasonable;
2) allocate low cost gas to existing firm sales customers;
3) allow buyout payments that might result in wellhead prices being paid that exceed the maximum lawful prices under Title I of the NGPA;
4) in effect deregulate Block 2 after four years abandoning historical cost-based standards for determining just and reasonable rates;
5) allow unilateral abandonment of firm gas sales contracts; and
6) allow a party other than a pipeline to apply for a certificate for service on behalf of the pipeline.

We encourage the Commission to avoid as much uncertainty as possible by acting on those issues that could lead to protracted litigation. I recognize, however, given the breadth and complexity of the Commission's NOPR, that the probability of lawsuits being brought by several parties on a diversity of issues is likely to remain a dark cloud hanging over the rulemaking.

CONCLUSION

The Commission has undertaken a radical restructuring of the interstate natural gas pipeline industry. Although we support the Commission's overall goal, the basic framework requires modification and clarification to meet its objective and to have a legally sustainable rule. It is critical that any final rule adopted in this proceeding not inhibit interstate natural gas pipeline companies from competing for markets on equal terms with the other segments of the industry. In addition, there appear to be numerous areas, as pointed out, where the Commission needs to address further the operational effects of the proposal as well as its legal footing so as to better assure a sustainable rule.

INGAA and its member companies are vitally interested in working with the Commission to assure a final rule that will achieve the objective set forth in the NOPR and also that will be within the bounds of sound pipeline operation.

Mr. Chairman, this concludes my statement, and I will be happy to answer any questions.

Senator NICKLES. Thank you very much, Mr. McGrath.

Mr. Terpstra.

STATEMENT OF WILLIAM C. TERPSTRA, PRESIDENT, NATURAL GAS PIPELINE CO. OF AMERICA, A MAJOR SUBSIDIARY OF MIDCON CORP.

Mr. TERPSTRA. Thank you, Mr. Chairman.

I also have a written statement which I would appreciate being read into the record, and I will try to summarize the key points of it.

Senator NICKLES. Thank you.

Mr. TERPSTRA. I'm the president of Natural Gas Pipeline Co. of America. We're the major subsidiary of MidCon Corporation.

We sell just under 1 trillion cubic feet of gas annually, predominantly in the northern Illinois, the northwestern Indiana, and Iowa regions of the United States.

Current conditions in the natural gas industry are very unsettled.

The NGPA has worked and elicited the supplies the industry sorely needed. However, the shortages of the 1970's have produced a layer of rigid contracts.

The actions of the FERC since 1983 have allowed more competition, which has created more options for our customers.

Access to transportation has increased. The end result is that gas prices are feeling the tension of the marketplace and are declining at the present time.

The markets in the Midwest are also undergoing this intense price competition, as pipelines reduce their prices to hold and recapture market share.

Not only are we faced with declining residual fuel oil prices and direct end-user purchases, but our pipeline also faces intense gas competition from other pipelines, producers, and brokers.

On July 1, we lost, temporarily, I hope, sales of 600 million cubic feet a day due to a competitor beating our price by 1 cent.

Under FERC's present rules, Natural does not have the rate flexibility to lower its prices, to cut its margin, and, even if we renegotiate our gas costs downward, we cannot reflect the change without filing and waiting for FERC approval.

Many of our nonpipeline competitors, such as producers, have no such restrictions. We do not deem this equitable.

In order to meet the competition under present rules, we have intensified our efforts to renegotiate gas contracts. To date, we have renegotiated price ceilings on over 300 contracts, covering about 200 producers.

We recently, about July 1, marketed out on market sensitive contracts $2.50 per million Btu's delivered on to our pipeline. Producers today are receiving the correct price signals under the current system.

I feel pipelines are ready to compete and transport, but we must have freedom comparable to other buyers and sellers.

To switch subjects, I would like to briefly comment on the recent notice of proposed rulemaking, or NOPR. This is more fully discussed in my written testimony, but I'll try to briefly summarize the high points.

In our view, NOPR seeks to expedite the transition to a more market-oriented industry. However, there are some significant features in this proposal which are very troubling. Namely, their abandoning of rolled-in pricing for the new block pricing method, the take-or-pay buy-out concept, the unilateral right given distribution companies to walk away from their contractual commitments, and indirect mandatory carriage.

It is our desire to compete the transition without a lengthy period of uncertainty, or without major damage to any industry segment.

In this regard, we are concerned that the Commission's legal authority to implement the NOPR proposals will be questioned.

Given the significant proposed changes in the relationships between producers, pipelines, distributors, and end-users, numerous legal actions, perhaps taking years to resolve, and perhaps creating confusion, may well result.

This is not a desirable transition.

We believe in prospective changes, NGPA-wise. Retroactive actions are often destructive, and you can never fully level the past between all industry segments and all companies.

The first feature, the block pricing method, would divide gas supply into two blocks. The proposed second block, all gas except low-cost old gas, for Natural represents an annual volume of over 600 billion cubic feet per year.

This gas is not presently marketable.

Customers will attempt to maximize block 1 purchases and avoid block 2 purchases. Bypass of pipelines by distribution companies will result, and end users will attempt to bypass distribution companies.

The effect of these dislocations in the long run will be higher cost to residential users and perhaps a shortage of gas supply.

We believe a better solution is to leave all pre-NOPR gas in one block and give all pipelines a new block going forward. This enhances the market signals as the new block would contain new and market responsive contracts, while avoiding a retroactive allocation of contracts into blocks.

An alternative that we think is also acceptable is to create a new block for new and renegotiated contracts. In either event, we feel the blocking, as proposed, must be changed.

The second feature, the take or pay buyout formula, will unnecessarily increase the cost of gas to consumers. By use of the formula approach, FERC is signalling to producers exactly how much they can extract.

Natural's take-or-pay exposure under NOPR will be considerable. It could be as high as $1 billion in 1986 alone.

Our solution to this problem is to require producers who desire transportation rights to waive take-or-pay obligations in their contracts as a condition to pipeline access. All industry segments should share in the pain of the transition.

The third feature is the right of distribution companies to walk away from their contract obligations.

Our system was built and gas supply was acquired for these customers based on their market demands. We believe that if customers reduce their contracts, they should be required to convert to firm transportation with us for the remaining life of their contract. They should also be required to pay their fair share of take-or-pay if it is not ameliorated in any other fashion.

Without these changes, in our view, frankly, NOPR is less attractive than complete deregulation. Under NOPR, pipelines would lose the benefits of old gas but be subjected to an inferior market position, significant take-or-pay exposure, and increased operational regulation.

Under NOPR, the random distribution of benefits and costs among the elements of the gas industry and individual companies is neither equitable nor appropriate.

A retroactive tilt in the playing field is poor policy, in our view.

Under NOPR, pipelines who have managed their businesses and made investments or contractual commitments in good faith, based on the conditions environment at the time, are penalized.

However, be assured we do not wish to live in the past or retain the status quo. We are on the road to the brave new world, like it or not.

We cannot stop where we are today.

We agree with the FERC and what we believe to be the wishes of Congress that we should have a more market responsive industry better to serve the consumer.

Thank you.

[The prepared statement of Mr. Terpstra follows:]

BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION & CONSERVATION
COMMITTEE ON ENERGY & NATURAL RESOURCES
UNITED STATES SENATE

HEARINGS ON CURRENT CONDITIONS AFFECTING THE NATURAL GAS MARKETS

STATEMENT OF

WILLIAM C. TERPSTRA
PRESIDENT
NATURAL GAS PIPELINE COMPANY OF AMERICA
A MAJOR SUBSIDIARY OF
MIDCON CORP.

July 11, 1985

STATEMENT OF WILLIAM C. TERPSTRA
ON
CURRENT CONDITIONS AFFECTING THE NATURAL GAS MARKETS

My name is William C. Terpstra and I am President of Natural Gas Pipeline Company of America (Natural). Natural is the largest subsidiary of MidCon Corp., the parent of a diversified group of energy-related domestic companies. MidCon subsidiaries operate primarily in the Mid-Continental United States and engage in three principal lines of business: natural gas transmission and marketing; oil and gas exploration and production; and onshore contract drilling. MidCon became operational in late 1981, but its subsidiary companies date back to the early 1930s. More than 5,000 persons are employed in the MidCon workforce. In fiscal 1984, its revenues topped $4 billion, with net income of $146 million.

CURRENT STATUS OF THE NATURAL GAS MARKET

I appreciate the opportunity to present one view of the current status of the natural gas industry. In contrast to the gas shortages of the 1970s, the Natural Gas Policy Act (NGPA) has been effective in eliciting needed supplies while at the same time the price of alternate fuels has declined. Although the supply problem in the near term has been resolved, the industry is saddled with rigid layers of non-price responsive contracts from this post-shortage period. As a general matter, this contract problem is being resolved through the operation of competitive market forces within the existing regulatory system.

Natural sells approximately 1 Tcf of gas annually to distribution companies mainly in Iowa, Illinois and Indiana. Our markets are the northern Illinois - Chicago - northern Indiana metropolitan complex. Currently the gas market in the upper Midwest is undergoing a rapid adjustment in gas pricing. Competition is intense as pipelines reduce their prices to hold and increase market share. Not only are we faced with declining residual oil prices, but also our pipeline is facing gas pricing competition from major pipeline competitors. This competition has resulted in a decrease in rates at the Chicago city gate.

In order to meet competition we have to keep pressure on prices at the wellhead. We have intensified our efforts to renegotiate gas contracts. To date we have negotiated price ceilings on over 300 contracts covering some 200 producers. Natural's most recent use of market out clauses lowered prices to $2.50/MMBtu delivered to our system. Because of the competition at the city gate, we are constantly renegotiating and producers are receiving the correct price signals.

The large majority of producers have shown a willingness to renegotiate in good faith those deregulated gas price provisions which are inconsistent with market reality. However, efforts to finally resolve the pricing problems with our largest suppliers of deregulated gas are proceeding slowly and legal actions have commenced. The NOPR makes any meaningful discussion in this area very difficult.

One other action we are taking to keep our costs down is to transport gas for end users in our market area. Natural is presently hauling 82 Bcf of gas annually for these customers. Competition is present in our market area and I fully expect it to continue.

DISCUSSION OF FERC'S NOPR

Clearly, the most important current issue facing our industry is the Federal Energy Regulatory Commission's Notice of Proposed Rulemaking of May 30, 1985 (NOPR). It involves a complex four point program which, if implemented, would create sweeping changes in the natural gas industry. We support the overall objectives of the Commission's proposal based upon the belief that the marketplace and competition should be accorded a progressively greater role in the gas industry. Greater reliance on market forces will encourage efficiency, proper allocation of resources, and the competitive pricing of gas. The NOPR places the debate over changes in current regulatory requirements in the proper context: i.e., under existing legislation how can markets for natural gas be made more effectively competitive and the participants afforded greater flexibility and freedom of choice?

We have serious concerns with the legality, equity and practicality of some aspects of the Commission's proposal, particularly where the NOPR (i) adopts regulatory constraints or obligations in the name of competition; or (ii) fails to recognize fully or address adequately commitments or problems arising out of the previously existing legislative and regulatory framework. Our comments to the FERC will suggest modifications to the NOPR which we believe will serve to advance the overall objectives of the NOPR while avoiding countervailing problems of equity which can be avoided by alternate approaches. We support the end result sought -- a viable competitive market -- and believe our suggestions will assist the Commission in attaining that goal.

We believe that pipelines should continue to have the opportunity to compete for a significant role as buyers and sellers of gas. Pipelines have served this important function in the market and should be permitted to compete for it on an equal footing with new entrants in the future. Pipelines have the ability to balance thousands of supply sources to meet the needs of millions of consumers, which is important to ensuring firm, reliable service to homeowners and commercial gas consumers, particularly during the crucial winter heating season. The NOPR will encourage more transportation of gas as well as the entry of additional buyers and sellers into the market, a process which should increase competition and the effectiveness of market forces.

Thus, while the role of pipelines as buyers and sellers may diminish as transportation increases and new entities enter the market, we would submit that the pipeline role will continue to be important due to the physical realities of the gas industry -- the difficulties of balancing supply sources, transporting and storing gas and making it available during periods of peak demand. It is likely that many customers, especially the smaller distribution companies, will continue to rely on the expertise of pipelines to perform these traditional functions. While it is appropriate that pipelines be given incentives to transport, so that they are largely "economically indifferent" between sales and transportation, the new rules should not favor one class of seller over another, especially during any period of transition. Pipelines should have an equal opportunity to participate in all sectors of the gas industry.

Everyone should recognize that the current system has functioned reasonably well from a national perspective, with gas being the largest domestic source of energy. Today, service interruptions are rare, and under rolled-in pricing costs to consumers are responding to existing market forces.

We have three primary concerns with the NOPR which are as follows:

(1) Pipelines should be on an equal footing to compete with other pipelines as well as new market entrants (brokers, producers, etc.) to the industry. Under the NOPR block pricing proposal, pipelines will be discriminated against.

(2) The transition to a more competitive market will require changes by all segments of the industry.

  (a) Producers should share in addressing the contracts problem and should be given incentives to renegotiate.

  (b) Pipeline customers should share in the competitive pressures and the costs of transition such as take-or-pay.

(3) Payments to resolve transitional problems (primarily take-or-pay) should be minimized and considered as an offset to the benefits of receiving low cost "old" gas and the opening up of pipeline systems to transportation.

We are concerned that the Commission's legal authority to implement the NOPR proposals may be questioned. Given the significant changes proposed in the relationship of producers, pipelines, distributors and end-users, numerous legal actions - - - taking years to resolve - - - may well result. Such prolonged uncertainty will be extremely harmful to all segments of the industry.

To address these concerns, we are prepared to make specific suggestions as to how the NOPR could be revised and improved.

A. Block Pricing Structure

We believe that the continuation of the historic method of rolled-in pricing -- in place for some 40 years -- is the most equitable and appropriate. One does not need a long memory to recall that current gas supplies have been acquired under various market conditions to serve all of the long-term needs of the pipelines' customers. Moreover, the so-called "cushion" enjoyed by some pipelines did not happen by accident. In response to the emerging shortage of gas in the early 1970s, Natural commenced an aggressive gas supply acquisition program. Over a five year period, we expended substantial corporate financial resources - - - nearly 500 million in mid 1970s dollars - - - in an effort to insure adequate gas supplies at reasonable prices. All pipelines operated under the same regulatory rules. Some were more successful than others. As the result of our efforts, we presently have a large volume of low cost "old" gas. We believe that this program was a success and oppose any proposal which would have an adverse impact upon the large volumes of low-cost gas which resulted from it.

Under the Commission's proposed block pricing structure, pipelines would have to artificially isolate their low cost Block 1 gas from their remaining Block 2 gas. The NOPR would penalize pipelines by retroactively changing the rules of the game, thereby denying pipelines like Natural the benefits of their efforts. Also penalized would be those producers who have recently agreed to market responsive contracts. This is because pipelines would be required by the NOPR to disproportionally lower the price under such contracts in an effort to make Block 2 marketable - - - on average. Much of the Block 2 gas was developed under contracts negotiated during the period of gas shortages because customers were clamoring for supply at any price. The rigid price and take terms necessary to purchase such gas make the Block 2 gas unmarketable. Pipelines, therefore, will not be able to compete at the margin with, for example, new market entrants under the proposed "blocking" approach and will not be able to sell large portions of their Block 2 gas supply.

Natural suggests that if the proposed block pricing is adopted, it must be modified so that all pre-NOPR gas is placed in Block 1 while all post-NOPR gas is placed in Block 2. In this way, no one in the industry will be disadvantaged by an "after-the-fact changing of the rules". Contract negotiations taking place after the NOPR becomes effective will be with the full knowledge of its provisions. The wisdom and fairness of not engaging in retroactive regulation is best demonstrated by NGPA itself. Congress there recognized that changed rules should be applied prospectively in order to permit planning and to avoid industry-wide disruption.

Alternatively, if the currently proposed block pricing is assumed, all gas purchased under new or renegotiated market responsive contracts should be placed in a new, separate block (called Block 2(a)). The existence of such an additional block would enable pipelines to compete on a more equal footing with new entrants. The block containing gas contracted for during the shortage period and not renegotiated would still be unmarketable. However, at least the renegotiated and more recently contracted for gas would be price sensitive and could be sold. This proposed structure would also give producers an incentive to renegotiate contracts which are not market sensitive. In this way, they could move their gas into the new block, along with the other marketable gas, which the pipelines would be able to purchase and sell. This block would provide the necessary price signals to the producers. Natural estimates that this class of renegotiated old contracts, rollover contracts, and new contracts - - all with market responsive pricing provisions - - would amount to 300 - 350 Bcf.

B. Nomination of NGPA Section

Administration of the proposed block pricing mechanism will be difficult, and may face legal challenges. Many pipeline-producer gas contracts cover purchases from several NGPA sections. For example, under one contract it is common to purchase gas at different prices - - which under the NOPR as proposed would go into different blocks. However, the pipeline currently has no contractual ability to require such a production pattern by the producer and the producer has no incentive to comply. Under the pricing structure of the NOPR, it seems likely that most gas purchasers will request all the "old" gas available, buy may desire far less Block 2 gas than is available.

We believe the Commission should explicitly order as part of its rule that the pipeline may request under its composite contracts (and the producer would be obligated to deliver) all Block 1 gas requested by the pipeline to the extent it can be produced prior to the delivery of Block 2 gas. This requirement is essential if the proposed blocked pricing approach is to function as intended and existing customers are to be assured historical levels of "old" gas production.

Moreover, the Commission should direct, with respect to gas in each block, that the pipeline follow a "least cost" purchasing strategy to the maximum extent consistent with the safe and efficient physical operation of its system. Such a directive would establish clear guidelines. It would also provide pipelines with bargaining leverage to insist upon such a purchasing pattern with their producers.

If the Commission believes it does not have the authority to impose such a purchasing pattern, it should not impose block pricing upon the gas industry.

C. Contract Reduction

The NOPR contract reduction right on the part of customers of the pipeline is an interference with private contracts which we feel is unlawful and unwise. Pipeline systems were built based on the demand for service by existing customers. The NOPR gives customers the unilateral right to walk away from their contracts. Natural believes that customers exercising this unilateral right of contract abrogation should be required to convert to firm transportation service, with a facilities charge being imposed on them for the duration of their service agreement. They also should be required to pay their fair share of take-or-pay caused by their contract abrogation. These steps are necessary to avoid unfairly shifting costs among customers and to properly allocate the costs imposed by such customers on the pipeline system, based on the contract demand they originally contracted for but elected to eliminate.

D. Take-Or-Pay

The NOPR could result in very large increases in take-or-pay liability, thereby increasing the overall price of gas to the pipelines' remaining customers. Natural's Block 2 gas amounts to some 600 Bcf annually. In the event substantial quantities of this gas go unsold under the NOPR, we estimate our take-or-pay exposure could be over $1 billion for 1986 alone. The buy-out mechanism and ceiling concept proposed in the NOPR is not an effective way of dealing with this problem. It will merely encourage producers to demand at least the ceiling as the minimum amount of the prescribed payments. The NOPR provides producers with no incentive or inducement to renegotiate their contracts. This will result in a valuable resource being shut in because it is unmarketable. We believe that the Commission has not demonstrated that its proposal works, nor that the potential cost is justified. The Commission should permit greater flexibility in pipeline-producer arrangements to deal with this problem.

If the interstate system is to be opened up to greater transportation access and competition, producers desiring to avail themselves of this open transportation system should be required to waive take-or-pay provisions in their gas contracts with those pipelines offering transportation services. Producers as well as pipelines should share in the transition to a more competitive, less restricted industry. As an incentive, those producers which agree to new contract terms could be given some type of preference with respect to available transportation capacity.

E. Carriage

The Commission's NOPR transportation proposal is essentially a form of mandatory carriage. We do not object to open access to our system, but we must retain discretion to restrict availability on the basis of considerations of efficient operation of the system. By way of example, a customer seeking a short haul in the middle of a pipeline system should not be able to create a bottleneck which prevents efficient use of capacity on the entire system. Also, because transportation rates will be on a volumetric basis, the pipeline must have assurance that the capacity set aside for a customer will in fact be used. Nor should customers be able to tender below quality gas, thereby undermining proper operating procedures and safety standards. The NOPR must be modified to allow the transporter such discretion.

In the natural gas industry, agreements effecting capacity availability and efficiency of operations should be left to the pipeline and its customers. If some regulation is required, we suggest that an expedited protest procedure might be appropriate for anyone refused transportation.

In conclusion, while we support the thrust of the Commission's proposal based upon the firm belief that market price and competition should be given a greater role in the gas industry, it is quite clear that the NOPR as presently configured does not result in the "level playing field" contemplated by the Commission. In point of fact, it will create a new set of comparative advantages and disadvantages in the natural gas industry which will act to frustrate the concept of fair competition. We believe our suggested changes to the NOPR will accomplish the goals of the proposal with a quicker and less painful transition.

Senator NICKLES. Thank you very much, Mr. Terpstra.

Mr. Lawrence.

STATEMENT OF GEORGE H. LAWRENCE, PRESIDENT, AMERICAN GAS ASSOCIATION

Mr. LAWRENCE. Senator, let me focus on the two questions you raised: the new gas deregulation provisions of the NGPA, how have they affected supply, the answer is a very dramatic improvement. You referred to the impact of NOPR. We'll have some very detailed comments on that to offer to the commission.

But let me emphasize the single most important point that's very relevant to your bill, and that is the take-or-pay problem, which Mr. Terpstra referred to.

There are some problems with the take-or-pay provisions of the NOPR which we will address. But the single most important solution to take or pay is to improve demand for natural gas in this country.

Your bill addresses that very directly and explicitly, and we applaud you for it. And you do it without some of the baggage of additional Federal controls that statutory mandatory carriage would apply.

So I'd like my comments to focus on the essence of your bill, S. 1302, and that of Senators Domenici and Bennett Johnston of this committee, S. 1251.

Both of those bills address supply and demand for natural gas.

Mr. Bush indicated that we sometimes disagree with their interpretation of reserve figures. That's an understatement.

Reserves for 40 years have been estimated on the basis of new additions and extensions to existing fields and revisions, up and down. As you get more information, you make revisions.

Now, in the period preceding the NGPA, reserve additions were less than 48 percent of production, less than half. In the period since the NGPA that went to 70 percent in 1979, it went to 90 percent in 1980, and in the 4-year period, using the EIA numbers and with an estimate for 1984, in that 4-year period, 1981, 1982, 1983, and 1984, reserve additions have more than equaled production.

Now that's a very dramatic improvement of the new gas supply incentives of the NGPA.

I believe I heard reference to a 10-year supply. There is indeed a 10-year reserve production ratio on the proved reserve estimates in the lower 48 States, and the supply pessimists and particularly our competitors in the marketplace will frequently try to impute to us that we're falling off a cliff in 10 years and won't be around to compete with them. It couldn't be further from the truth. That's a moving target. That R/P ratio has been about 10 years in the proved reserve end of the supply spectrum—for over 15 years. You keep adding to the proved reserves from the potential conventional supplies in the lower 48 States. And when you look at those potential conventional supplies, you have a 50-year R/P ratio.

Now, that potential conventional itself is a moving target. You keep adding new technology reserves, tight formation reserves, for example. Over the past 5 years, over 170 trillion cubic feet have been moved from a new technology category into this potential category.

Now, when you look at just the new technologies in the near-term, tight formation, Devonian shale, coal seam gas, you're talking about a 200-year R/P ratio. And we haven't even begun to focus on some of the new technology, exotic breakthroughs that might come from geopressure, abiogenic sources, gas hydrates, or something like that. We're talking about truly inexhaustible supplies.

So the resource base has been there. The supply situation now is good, and every prospect for that remaining good for the long term, unless we do some very stupid things. And reimposing field price controls would certainly be one of them.

But one of the biggest disincentives now producers have is a lack of demand, and to continue to have a Federal statute in a time of oversupply that says you can't use natural gas in new, industrial applications of over 2.5 million cubic feet a day, which is about the size of one small gas well, is a very poor public policy. That needs to be repealed.

Clearly, there is a consensus in this Senate, in this Congress, to repeal it. The question is how much baggage gets put on it to the point where you can't accomplish that repeal.

How important is the market restraint repeal of the Fuel Use Act and incremental pricing?

A.G.A. made a study in August 1984. We submitted this to all members of this committee back then, that quantified that, Senator, in our projection. I would like to include that along with my prepared remarks as a part of the record in this proceeding, if I may.

Senator NICKLES. OK.

Mr. LAWRENCE. It showed a cumulative loss of market of 26 trillion cubic feet due to the Fuel Use Act by the year 2000 and by the year 2000, that would amount to about 3 trillion cubic feet a year, a very significant market loss.

Such things as the cogeneration, a highly efficient use of energy to the end-user, is being impeded by the Fuel Use Act. The select use of natural gas with coal that would permit coal to meet its environmental commitments in what we think in most cases is the most economic standard and would also permit it to compete better with imported hydropower from Canada, combined cycle application of natural gas, which is flat roadblocked by the Fuel Use Act—these all have tremendous new market applications now, and the Fuel Use Act repeal would get rid of those.

Your bill does that, and we applaud that.

I've already mentioned and applaud the fact that your bill does not get into the Federal statutory mandatory carriage, which would be an additional layer of regulation on our industry, just at a time when we are coming out of 30 years of field price control.

As to your addressing old gas by contract expiration or when the old gas contracts for section 104 gas are renegotiated.

I think as you know, Senator, and as Senator Ford knows, the American Gas Association has long been a proponent of new gas deregulation prospectively, yes—that's why we supported the NGPA—old gas deregulation, no.

We'd say this, though, that you're addressing of this by the contract expiration and renegotiation is, we think, the most benign way we know of of addressing that issue, and would have the most modest impact on field prices in any way. We made such an analysis of that when you introduced your bill 2 years ago, and the results of that analysis were passed around. But the focus was on a different bill which did not get out of the Senate.

But, again, we will continue to look at that. But we would also add that the bill that we think is right on target, that does the doable and accomplishes what needs to be done, is S. 1251, and we certainly applaud Senators Domenici and Johnston for introducing that repeat of the Fuel Use Act and incremental pricing, period, without anything else. A rifle shot approach is needed and is needed desperately.

Now, A.G.A. has long supported the supply incentives of new gas field price deregulation. We would continue to support the increased access to drilling acreage in the OCS and other Federal lands. We applaud use and others, and we would support the retention of the tax incentives that are so vital to future exploration and drilling, and particularly the 1-year intangible drilling write-off.

Also, we're very supportive of a continuation of long-term gas-related research, because that's the way we're going to get at this tremendous resource base that could make the natural gas supply truly inexhaustible.

So, in conclusion, Senator, I would just say that I think the trends since passage of the NGPA have shown that there is a tremendous contribution that the natural gas resource base in the United States can make to our future energy policy, both to our energy policy goals, our economic goals, and our environmental goals. We're on the road of getting rid of the shackle of field price control that put this industry in a bad way when they were imposed on us for over 30 years. We have had, for the past 8 years, another shackle, and that's on the market end of our business, and that needs to be repealed. Then, I think, the market forces, this industry's innovation, and aggressiveness, will really lead to natural gas making the contribution it's entitled to make and that the consumers of this Nation are entitled to receive.

Thank you.

[The prepared statement and study submitted by Mr. Lawrence follows:]

TESTIMONY OF
GEORGE H. LAWRENCE, PRESIDENT
AMERICAN GAS ASSOCIATION
BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE
ON THE STATUS OF THE NATURAL GAS INDUSTRY
July 11, 1985

Introduction:

Mr. Chairman and members of the Subcommittee:
My name is George H. Lawrence, and I am President of the American Gas Association. I am pleased to have been invited to speak to you today on the status of the natural gas industry.

The American Gas Association (A.G.A.) is a national trade association composed of nearly 300 natural gas companies in all 50 states. Collectively, our member companies account for 85 percent of all gas utility sales. A.G.A. represents all segments of the natural gas transmission and distribution industry: distribution companies, interstate pipelines and intrastate pipelines alike. Therefore, A.G.A. is in the unique position of being able to give the members of this Subcommittee the perspective of the entire distribution and transmission industry, not just the views of one segment of the industry.

My testimony today will be broken down into four sections. The first section is a brief summary of our testimony as a whole. The next two sections discuss the current situation of the gas industry with respect to: a) supply; and b) demand. In these sections, I will also inform the members of the Subcommittee of the changes facing the gas industry, and the industry's responses to such changes. The final section will discuss those areas in which Congress must act to bring governmental energy policies in line with the facts existing in today's energy world.

I. SUMMARY

From where we stand today, the future prospects for the natural gas industry look extremely promising. As I will detail for you later in my testimony, gas supply is no longer a physical constraint to selling gas -- although it is still on the minds of the gas customer. On another front, A.G.A. confidently predicts a growing gas demand, which could be dramatic growth if it is allowed to take place free from the chilling effects of such market constraints on natural gas as the Fuel Use Act and incremental pricing. In addition, on-going structural and regulatory changes will result in a more aggressive and competitive gas industry.

Overall, gas energy and the gas industry are free of most of the problems that face our competitors. Oil is still imported and relatively expensive. Nuclear power is not a viable option for the generation of electricity in the foreseeable future, beyond those plants already under construction. Coal has production, consumption, transportation, and environmental problems.

These factors lead to one conclusion: Over the next several decades, U.S. energy requirements should gradually increase -- and natural gas is the fuel best positioned to satisfy these new energy requirements and meet our nation's vital energy needs into the 21st century and beyond. However, in order to allow gas to fit into its natural role in this regard, Congress must

- o remove the artificial demand constraints of FUA and incremental pricing that were put on natural gas at a time when the gloom and doom prognosticators predicted that our nation would run out of gas.
- o encourage optimal domestic natural gas production -- including reasonable and equitable tax treatment of natural gas production activities, adequate Federal funding levels for gas-related R&D, and allowing for full development -- within reasonable environmental guidelines -- of natural gas production in our public lands and OCS areas.

II. THE CURRENT SUPPLY SITUATION

"But many that are first shall be last; and the last shall be first" (Matthew 20:30). This biblical quotation is appropriate for today's gas industry. Eight years ago, the Deputy Secretary of Energy was loudly announcing to all listeners that there were only seven years of natural gas left, and that gas had "had it" as a major fuel source. The First National Energy Plan by the U.S. Department of Energy (DOE) wrote natural gas off for supply reasons -- and did so in such a panic mode that DOE even suggested substituting oil for gas in certain applications.

This pessimistic outlook was due to the natural gas shortages experienced in the mid 1970's. These shortages were the result of over 20 years of government-mandated natural gas wellhead price controls, which kept gas prices depressed below market levels, discouraging gas exploration and production while artificially stimulating demand. As a result, it appeared that we were running out of gas when we were actually just facing the natural consequences of unjustified government intervention. In response to this situation, Congress passed the Natural Gas Policy Act of 1978 (NGPA), which initiated a phased shift to wellhead decontrol for various categories of "new" gas (generally from wells drilled after February 1977).

As a result of the NGPA, the gas supply outlook has changed dramatically -- and, with this change, the domestic energy outlook has changed as well. Natural gas is now widely viewed as a critical component of both our national energy and environmental agendas. Since passage of the NGPA, natural gas has displaced a net volume of 290 thousand barrels of oil use per day in the industrial sector. Over this same period, in the residential sector, 1.7 million homes have converted to gas from oil. These trends are continuing today, reducing our nation's dependence on imported oil.

All of this has been made possible by the dramatic improvement in natural gas supplies since the NGPA was enacted. These supply improvements in response to the higher NGPA prices have demonstrated conclusively that interstate market gas supply problems during the 1970's reflected the inadequacies of wellhead price controls rather than the limits of the domestic gas resource base.

However, in spite of the complete turnaround in the gas supply situation after passage of the NGPA, one legacy of the 1970s supply problem remains. This legacy is an underlying misconception that the gas resource base is nearing depletion and that the marketplace must therefore eventually choose between much higher gas prices or renewed gas scarcity. This incorrect assumption of a resource base that is nearing depletion, and its impact on projected gas supplies and/or prices, has resulted in gas supply pessimism. Time, and a continuing record of gas supply adequacy, will overcome these negative perceptions to a certain extent. However, certain actions by the Federal

Government -- which would bring its policy in line with the world as it exists today -- will be needed to ensure the return of consumer confidence. I will outline the necessary Federal actions a little later in my testimony.

Natural Gas Pricing Posture

On January 1, 1985, as a part of the schedule set by the NGPA, wellhead price controls were removed from the majority of flowing natural gas supplies. When the NGPA was passed in 1978, the average wellhead gas price was $0.91 per thousand cubic feet (Mcf), and the average retail gas price was $2.23/Mcf. By 1983, the average wellhead gas price was $2.62/Mcf and the average retail price was $5.25/Mcf. Gas prices in 1984 were stable, and gas prices are declining in 1985.

Originally, it was feared that gas prices would "fly-up" sharply upon new gas decontrol in 1985. This concern sprang from speculation that : (1) the NGPA price ceilings were too low relative to oil, thereby keeping new gas below its decontrolled market value; and/or (2) decontrol would trigger indefinite escalator clauses which in turn would rocket the price of large volumes of gas to levels far above market value. These expectations proved incorrect, however. Instead, events demonstrated that : 1) under current conditions, gas competes primarily against relatively inexpensive residual oil rather than against high-priced distillate oil; and 2) the regulated gas industry has [illegible] ability to manage "problem" contracts at the wellhead. As a result of these and other developments, A.G.A. now projects that gas prices will decline in real terms for the rest of the decade. Between now and the end of 1988, A.G.A. expects that national average retail prices will decline by 4 percent per year. Similarly, we also expect that wellhead gas prices will decline 3 percent per year during the same period.

As you can see, we expect that retail gas price declines will slightly outpace wellhead gas price declines. Our anticipation of this effect is based on our assumptions that: a) increasing gas-to-gas competition will increase industry operating efficiency; and b) increasing gas demand will permit fixed system costs to be spread over a larger base of gas volumes, thereby reducing fixed system costs per Mcf delivered.

Natural Gas Supplies

The U.S. natural gas production level in 1984 was roughly 17 trillion cubic feet (Tcf). The nation has discovered -- and has available to be produced -- 166 Tcf of proven reserves in the lower 48 states. These 166 Tcf have been booked as corporate assets of the companies that own them, and 88 per cent of this gas has already been sold (or "committed") to purchases. The Potential Gas Committee -- the industry group that evaluates gas resources -- estimates that, with currently foreseeable technology and economics, there are 647 Tcf of potential gas resources in the lower 48 states still awaiting discovery. This estimate of potential resources is in addition to the 166 Tcf of proven reserves. Therefore, estimated conventional gas resources total 813 Tcf -- or the equivalent of 50 years supply at the 1984 level of gas production. This 813 Tcf is referred to as lower 48 states "remaining recoverable resources", and does not include resources contained in Alaska's onshore and offshore areas.

The perception that the nation is "playing out" the remaining recoverable resource base over time has become the principal rationale for projections that gas production will steadily decline and that this decline will in turn force higher gas prices. This pivotal perception is mistaken because it is based upon the calculation of the gas resource base is a static -- rather than dynamic -- assessment. History has proven that the gas resource base is indeed dynamic, changing radically with technology development. For example, over the past 10 years, some 170 Tcf of new technology gas has been moved into the conventional category from tight formations, and from deeper horizons onshore and offshore that are now believed to be technologically feasible to drill for and produce.

The assertion that gas supplies must eventually decline, because of the finite nature of the recoverable resource base, is incorrect. The recoverable resource base is just the "tip of the iceberg" when one is assessing total gas resources in place in the United States. We estimate that a reserve life of over 200 years is available if we include gas in the near term new technology categories such as Western tight formations, Devonian shales, and coal seam gas, where new technology is expected to make development feasible in the near term. When we get into the more exotic resource bases that would require a genuine research breakthrough -- such as gas in the geopressured zones, gas hydrates, abiogenic sources, and renewables -- we are talking about virtually inexhaustible supplies of natural gas energy. Overall, the gas resources in place in the U.S. may turn out to be several thousand times our current consumption level. Indeed, a research breakthrough in any one of the previously mentioned areas would confirm our optimism by making natural gas our largest domestic source of energy.

Finally, I would like to point out to the Subcommittee that poor energy demand -- and especially poor gas demand -- has recently combined with the uncertain future tax treatment of production-related costs to bring the rig count down. To assure optimal production of natural gas supplies in the years to come, Congress must act to: a) increase demand by repealing artificial demand constraints on natural gas; and b) allow reasonable tax treatment of production-related costs. A.G.A. is just as concerned about this situation as the producers are. I will address these issues later in my testimony.

Gas Deliverability -- Short Term Surplus

A.G.A. has forecast that the excess short-term production capability (the so-called "gas bubble") will last at least another two years, and possibly for the rest of the decade. Our view is reinforced by the change in the Canadian Government's pricing policy for gas exports: a policy that is making more gas available to U.S. energy consumers at prices that the marketplace will accept. Recent announcements of renegotiation of long-term Canadian gas contracts to more competitive prices, and the developoment of a spot market for Canadian gas at or below $3.00 per million British thermal units (MMBtus), reinforces our current assessment that surplus deliverablility will persist for at least two more years.

A.G.A. estimates that the domestic gas bubble (that is, the surplus deliverability of U.S. gas supplies) will be about 2.9 Tcf in 1985, up slighlty from 1984 and down from 3.9 Tcf in 1983. Recent Energy Information Administration survey data results for 1985 show absolute stability in the size of the bubble.

After the continuing surplus has ended, we expect that gas supply and demand will be in balance. That is, there will not be a gas shortage and, as a direct result, there will not be the significant upward pressure on wellhead prices that some analysts have forecast. I cannot stress too much the importance of this fact to those legislators who will establish the future energy policy of our nation.

A.G.A.'s assessment of lower 48 states gas supply stability is also supported by the fact that the replacement of production with new reserves -- i.e., reserve additions -- has far exceed the expectations of just a few years ago. In the period 1981-1984, aggregate reserve additions in the lower 48 states were roughly 100% of production. 1984 was the fourth consecutive year when additions nearly equalled or exceeded production. In other words, "gas reserves" have stabilized at roughly their 1980 level. This level of replacement is a far, far cry from the decade preceding the NGPA -- 1968-1978 -- when reserve additions averaged only 46 percent of production.

The U.S. is currently in its eight year of an 18 month delivery surplus. The pundits that forecasted an 18 month delivery surplus following passage of the NGPA in 1978, and severe gas shortages between 1982-84, are now predicting shortages in 1986-87. These forecasters were wrong in 1982-84, and will be wrong again in 1986-87.

III. THE CURRENT DEMAND SITUATION

Interfuel Competition

Since 1962, constant-dollar gas prices have gone through a period of decline (1962-72) followed by a period of rapid increase (1973-83). As I discussed earlier in my testimony, 1984 marked the beginning of a third phase that will likely be characterized by gas prices approximately tracking inflation. Wellhead gas prices are projected to decline in real terms at an average annual real rate of more than 3 percent from 1983 to 1988. From 1988 until 1995, wellhead gas prices are projected to increase at a real rate of less than 2 percent annually. National average retail gas prices are projected to experience a similar pattern, declining by nearly 4 percent annually from 1983 to 1988, and increasing from 1988 to 1995 by only 1 percent per year.

Perhaps the most dramatic event that is occurring (and will continue to occur, in A.G.A.'s opinion) is the improvement in the compeitive position of gas relative to electricity on an energy equivalent basis. For example, in 1983, gas held a 3.5 to 1 advantage over electricity in the cost per unit of energy delivered to the residential sector. In 1983, the gas advantage increased to 3.8 to 1. This year, the ratio will exceed 4 to 1. Even when the impact of electric heat pumps is factored in, the initial gas-to-electricity cost ratio is so commanding that gas should remain the more economic choice. Indeed, A.G.A. anticipates a 1990 return to a 5 to 1 advantage: the level that existed in 1976.

The ratio of distillate oil price to gas should remain between 1.4 and 1.6 to 1.

When we apply these factors to specific markets, favorable trends for gas are expected in the commercial and residential sectors.

In addition, in the industrial sector, natural gas is expected to retain a significant price advantage over residual oil. The ratio of residual oil price to natural gas price is projected to rise from approximately 1 to 1 in 1984 to 1.2 to 1 by 1995. The price advantage of coal is projected to remain between 40 to 50 percent of the price of natural gas. However, this initial price advantage for coal can be more than offset when operating, maintenance and capital costs of coal combustion are considered.

The improved outlook for gas prices has been widely recognized in both the private sector and government. For example, in 1981 the EIA forecast that wellhead gas prices would exceed $9.00 per MMBtus in 1995 (in constant 1984 dollars -- adjusted by A.G.A. from constant 1980 dollars). By 1983, that estimate for 1995 had been lowered to about $6.50/MMBtus, and this year it was further reduced to $5.05/MMBtus.

Recent Levels of Gas Demand

Total U.S. gas consumption was 19.6 Tcf in 1978. Consumption remained fairly constant after passage of the NGPA, until 1982. For the next two years, gas demand declined sharply -- to 17 Tcf by the end of 1983. The main causes of this demand decline were the economic recession, which affected major gas consuming industries the hardest; significant price-induced conservation; and increasing interfuel competition in traditional gas markets. (The price-induced conservation and increased interfuel competition were predictable results of phasing out below market price controls.)

Overall, 1984 was a year of recovery, with gas demand estimated to total about 18 Tcf. In 1985, gas consumption is projected to remain relatively stable.

This stability of demand in 1985, following a year of growth, is expected for three reasons: (1) the very cold weather experienced in most parts of the country in 1984 has not been repeated thus far in 1985; (2) the economy in general, which recovered from the recession in 1984, is seeing slower growth in 1985 -- and the recovery of the manufacturing industry in particular is not continuing at the pace set in 1984; and (3) because the gas industry recaptured in 1984 a significant portion of industrial load that was previously lost to oil. The ability to capture additional load from oil is therefore limited.

After demand stability in 1985, gas demand is expected to increase gradually through the end of the decade.

Potential for Penetrating New Markets

There have been some major developments in key gas markets since passage of the NGPA. I will spend a few moments summarizing several of the marketing developments which could have a significant impact on natural gas demand in the foreseeable future.

New housing -- The market position of gas in new housing seems to have improved dramatically. The market share for gas heat in new single family homes, which has been on the decline, increased to 45 percent in 1984. This compares with 40 percent in 1982 and 37 percent in 1978. With gas prices stable and ample supplies available, A.G.A. expects that natural gas will continue to make inroads in the new housing market.

Industrial and commercial cogeneration -- About 40 percent of total current cogeneration capacity is gas-fueled, with 50 percent of new capacity being gas-fired. The economics of cogeneration continue to improve, given our projections of gas price stability and increased electricity prices. However, the Fuel Use Act requires an exemption for gas used in congeneration. This may dampen interest in using gas for purposes of cogeneration.

Gas cooling -- A number of factors have emerged over the last two years, improving already established market opportunities for gas cooling. These include the escalation in the price of electricity, particularly peak period electricity; the stability of gas prices; and the increased availabilty of gas supplies, with significant unused transportation capacity available in the summer. By reducing the gap between low demand days and peak demand days, increased use of gas cooling in commercial buildings could increase the operational efficiency of both gas and electric utilities.

Select use of gas with coal -- This new market uses the clean-burning attributes of natural gas to improve environmental quality. Select use of gas can replace imported oil with domestic gas and domestic coal resources and maintain or improve air quality, Select use can also be used as a cost-effective means of reducing sulfur dioxide emissions -- a growing national concern. As part of the "bubble" policy approved by the U.S. Environmental Protection Agency, select use offers Air Quality Regions the opportunity to improve air quality while holding or attracting new industry.

There are already 25 select use applications in operation in the U.S. and Canada, but the potential use level is much higher. The major obstacles to selected use are State and local regulatory barriers, the fact that there is no explicit Fuel Use Act exemption for select use of natural gas, and indifference. It is an area where coordinated planning among private sector companies, regulators, and energy suppliers is necessary for a project to go forward.

Combined-cycle gas turbines for central station electric power generation -- This is a new, environmentally benign technology that promises unprecedented cost efficiency in the generation of eletricity. In a combined-cycle powerplant, gas is burned to turn a turbine, and the dissipated heat simultaneously fires a boiler. There are off-the-shelf units in the 100 megawatt (MW) range. These "pre-fab" units are made by General Electric, and are selling strongly in Japan. The reason they are selling well in Japan, and not in the U.S., is that Japan doesn't have a "Fuel Use Act" that says you can't use them. Indeed, as we have noted, the Fuel Use Act stands in the way of many select use and cogeneration applications as well. In fact, cogeneration is the only one of these three technologies that even offers the possibility of filing for a FUA exemption! I will discuss this problem later in my testimony.

Natural gas vehicles -- At the moment, the most promising market opportunity is fleet vehicle use where central fueling stations can be utilized. However, the ultimate market for gas-powered vehicles is potentially enormous. There is a clear economic appeal since the fuel cost of natural gas is about 60 percent the cost of gasoline. In addition, there is an environmental appeal: natural gas emits fewer pollutants than gasoline -- and emits virtually no carbon monoxide at all. Consequently, use of gas as a vehicular fuel can help a number of localities to meet air quality objectives. Furthermore, it can save money for motorists, as well as reduce our dependence on imported oil.

A.G.A. isn't talking about replacing the corner filling station -- yet! However, if one-half of the 16 million fleet vehicles in our country were converted to natural gas by 1990, it would create a new gas market of 1 Tcf -- and it would displace 500,000 barrels per day of imported oil.

These new marketing opportunities are being amplified by structural changes in the gas industry that will accelerate their growth. Gas pipelines, distributors, and producers are developing new marketing strategies in response to the changing requirements of their customers. In addition, regulators are beginning to recognize that flexibility is needed for gas companies to compete in a deregulated market.

Structural Changes in the Natural Gas Industry

The gas industry has inherited regulatory, contractual, and operational procedures developed during a period of short supply, minimal competition, and low prices. Not all of these procedures will be effective in an environment characterized by higher prices, adequate supplies, and intense competition. The Federal Energy Regulatory Commission (FERC) has recognized this fact, as have many State public utility commissions; these regulatory agencies have begun to react aggressively to reform regulatory practices that no longer fit today's market environment. As for the gas industry itself, several changes in gas purchasing and ratemaking practices are being initiated already to accommodate competitive forces at the wellhead, city-gate, and burner-tip. I would like to briefly outline some of these revolutionary changes for you.

1) Market-responsive price clauses in gas purchase contracts -- Such contract terms include market-out clauses, periodic price redetermination clauses and market "net-back" pricing. These types of clauses allow the industry to continue to use long-term contracts as the primary gas

contracting practice without incurring future problems of gas marketability.

2) Development of a spot market -- This is technically a short-term contracts market. Such a market allows uncommitted, marginal gas supplies to be sold at currently competitive prices. This market will also serve as a "bellweather" for the larger long-term contracts market. The spot market for gas performs a function similar to the crude oil spot market, although at present it is not nearly as large in volume as the crude oil spot market.

3) Negotiated carriage -- A number of end users and distributors have availed themselves of the opportunity to acquire part of their own gas supplies in the field. They have been motivated by desire for a lower price, or for greater long-term supply security, or both. The current trend toward greater use of negotiated carriage will continue because, in a free market environment, pipelines and distributors will increasingly find it profitable to offer transportation services to their customers. The availability of both traditional and carriage service will allow the gas transportation industry to tailor its marketing efforts to accommodate its customers' requirements.

4) Regulatory flexibility and innovative rate structures -- Ratemaking flexibility allows the gas industry to market gas effectively in highly competitive end use applications. Flexibility is essential for allowing gas to

maintain its market share against unregulated fuels (such as residual fuel oil). Rate flexibility may also be needed for targeting new markets -- such as natural gas vehicles and others that I discussed earlier -- which offer such public policy benefits as lower oil imports, lower consumer costs, and cleaner air.

Regulatory receptivity to ratemaking innovations is essential. Fortunately, there are a number of encouraging signs that this is happening. Presently, there are at least 40 companies with gas transportation tariffs currently in force; this is in contrast to the 21 companies that had such tariffs in force last year.

5) FERC's Notice of Proposed Rulemaking -- Because we are still in the process of developing the written comments that we will file with the FERC on July 15, we cannot comment in detail in the Commission's sweeping Notice of Proposed Rulemaking (NOPR). However, we can say that while there are several specific features of FERC's recent proposal which may exceed FERC's legal authority, or which just won't work in practice -- we support the overall goal of the NOPR. This goal is to allow competitive forces to work more efficiently in the gas industry: a goal that we certainly share. A.G.A. would be glad to forward a copy of our final comments on the NOPR to the Subcommittee after the July 15 filing deadline.

We add that the NOPR is only the latest in a series of Commission initiatives aimed at making the regulated gas industry more flexible, more competitive, and more efficient. In light of the Commission's past and present efforts to expand and encourage negotiated carriage, to resolve "regulatory lag" barriers that hinder industry flexibility, and otherwise to increase industry responsiveness to market forces, there is no need for Congress to consider mandatory contract carriage legislation.

In view of both the gas industry's natural assets and the structural changes that are now underway, natural gas is in a unique position to be the fuel of choice in our nation's future. We have the supply, our prices are stable and will remain so, and we have a million-mile transportation system already in place with the capacity to accommodate the upper range of our demand estimates to the year 2000. Ours is an efficient, economic, environemntally benign transportation system that is the envy of the industrialized world.

In short, natural gas is the optimal fuel for helping our nation clean up our environment; for bringing energy to American consumers at the lowest cost; and for increasing the nation's ability to make policy decisons -- without threat of blackmail from oil-producing nations -- that would be in the best interests of our nation, our allies and world peace.

The natural gas industry is doing its best to assure all Americans that there is plenty of natural gas available to accomplish all of these objective. However, Congress must act to reverse policies made at a time when the prevailing view was that we were running out of gas. I will now discuss those actions which A.G.A. hopes that Congress will take in the near future.

IV. A.G.A.'S LEGISLATIVE AGENDA

Before we begin our journey down the path of legislative reform, I will inform the members of the Subcommittee of A.G.A.'s overall goal in urging Congress to act on certain issues. A.G.A.'s member companies do not seek any artificial marketing advantages through legislation. Rather, what A.G.A. seeks is simply the ability to compete with other forms of energy head to head. A.G.A. strongly believes that, if the gas industry is allowed to compete on a "level playing field" with other forms of energy, natural gas will play an increasingly important role in meeting the energy needs of our nation. The marketplace is the proper forum for determining allocation of our energy resources, not government mandate. Having said this, I will now discuss with the members of the Subcommittee A.G.A.'s legislative agenda for the 99th Congress.

1. Gas Demand Constraints

In 1978, when Congress initiated phased decontrol of new natual gas by enacting the NGPA, Congress also enacted two statutory programs which now have the effect of artificially precluding opportunities for growth in natural gas demand: the Fuel Use Act and incremental pricing. These two laws were passed at a time when natural gas was considered a "dwindling" resource. As we have shown, recent history has proven this theory wrong. Therefore, it is time to reverse the policies that were established based on this misconception. Fuel Use Act and incremental pricing repeal is A.G.A.'s number one priority in this legislative session.

Given the importance that we place upon repeal of FUA and incremental pricing, we are delighted to see that repeal legislation -- S. 1251 -- has recently been introduced by Senators Pete Domenici (R-NM) and Bennett Johnston (D-LA). We believe that Senators Domenici and Johnston were ~~was~~ wise to take a "rifle shot" approach -- disentangling the repeal issue from other, more contentious matters and attempting to build on the relatively strong Congressional consensus in favor of repeal.

We are also pleased that the Chairman of this Subcommittee, Senator Don Nickles (R-OK), has introduced S. 1302, a bill on natural gas policy which includes repeal of FUA and incremental pricing. We commend Senator Nickles for recongizing the importance of repeal -- and we also applaud him for his decison to omit from the bill any provisions for imposing the divisive, unworkable, and unnecessary concept of mandatory pipeline carriage.

We note that Senator Nickles' bill does contain provisions for phased old gas decontrol that is pegged to the pace of scheduled contract expiration. A.G.A. has historically opposed decontrol of old interstate gas -- particularly if such decontrol occurs over a short time frame and therefore compresses the upward price impact. However, two years ago we did initiate a study of a phased approach to old gas decontrol that was generally similar to the Senator's proposal. Our study concluded that tying old gas decontrol to contract expiration dates would have a more modest price impact than any of the major competing approaches to old gas decontrol. In addition, we do not need a quantitative assessment to notice that the Senator's approach endeavors to hold to a minimum any disruption of existing contractual arrangements.

In short, while we are not currently in a position to endorse any proposal for decontrol of old interstate gas, we do commend Senator Nickles for his efforts to develop an approach which minimizes costs and disruptions. We will continue to study this type of approach -- and we may get back to you with additional observations in the future.

Moving to some specifics:

A) The Powerplant and Industrial Fuel Use Act (FUA) does not adversely affect opportunities to sell gas to those powerplants and industrial facilities built before April 1977. What the FUA does preclude is natural gas sales to all powerplants and industrial facilities constructed after April 1977, when such facilities have a rated design capacity of 100 MMBtus per hour or more. The FUA also: (1)

bans gas utility service to post-April 1977 gas lights; and (2) gives (currently unexercised) discretionary authority to the DOE for banning the use of natural gas by certain pre-April 1977 industrial facilities which can be shown to have the capability to burn either coal, or some other alternative to natural gas.

A.G.A.'s basic arguments for FUA repeal can be summarized as follows:

a) FUA precludes opportunities to save money for the consumer. By automatically barring the use of gas in large new factories and powerplants, FUA legally blocks otherwise available gas industry opportunities to compete for new sales. Thus, each gas consumer may have to pay a greater share of fixed system costs -- which translates into a higher utility bill -- than might otherwise be necessary. Furthermore, those consumers precluded from purchasing natural gas outright may be forced to pay more for a substitute fuel.

b) FUA discourages promising new technologies. A special exemption is needed for the use of gas in cogeneration -- despite cogeneration's high energy conservation potential. No FUA exemptions at all are allowed for two other promising technologies: a) the "select use" of natural gas -- as a secondary fuel, in conjunction with coal or residual fuel oil -- for purposes of reducing emissions that would otherwise occur; and b) the use of natural gas in modular block combined cycle generators in new powerplants: a technology which can reach a new high in energy efficiency, thereby giving the electricity consumer the same energy for fewer dollars.

c) The FUA could be a major "drag" on economic growth. A recent A.G.A. analysis -- which attempted to quantify the "worst case" impact of the FUA -- found that the FUA could cause a cumulative drop in gas demand of as much as 26.2 Tcf by the end of the century. If this gas demand were replaced by direct coal use and coal-generated electricity, the added economic burdens -- in 1984 dollars, over the next 15 years -- could be as much as: (1) $43.7 billion in otherwise unnecessary capital investment; and (2) $11.5 billion in added costs of generating elecricity. Furthermore, there could be major increments of new, otherwise avoidable, pollution. If instead the affected new powerplants and factories were not built at all, and were replaced by imported goods and electricity, the cumulative "drag" on the economy could: 1) eliminate up to 1.5 million otherwise available jobs; plus 2) boost the balance of trade deficit by up to $1,160 billion.

d) FUA repeal would not stop the market-driven trend toward increased use of coal. Although specific projections differ, numerous informed observers -- DOE, A.G.A., and the National Coal Association -- all foresee coal demand rising by 50 percent or more in the next 10-15 years. This trend is far too strong to be reversed by FUA repeal. Rather, by permitting greater reliance on "select gas use" as a pollution control measure, FUA repeal may actually increase demand for high sulfur coal.

B. The other gas demand constraint -- incremental pricing -- is not a statue in itself. It is Title II of the NGPA. Under incremental pricing, a complicated rate and accounting mechanism has been established. The "bottom line" impact is that, for most large industrial boilers which burn natural gas that was originally acquired by an interstate pipeline, the rates paid for such gas must be set at a minimum price of virtual parity with high sulfur No. 6 oil. In those cases where the otherwise applicable gas rates would be lower than the Btu equivalent price of high sulfur No. 6 oil, possible opportunities to displace imported oil are precluded artificially.

A.G.A.'s basic arguments for incremental pricing repeal can be briefly summarized as follows:

a) Incremental pricing precludes opportunites to reduce the use of imported oil. For industrial boilers, incremental pricing automatically boosts the gas price up to rough parity with the price of residual oil (even if gas would otherwise be cheaper). Saddling natural gas with this pricing handicap in its competition with imported oil makes no sense if a free market and energy self-sufficiency are truly national goals.

b) Incremental pricing distorts market preferences even for consumers who do use gas. Because incremental pricing affects only gas that is acquired by interstate pipelines, incremental pricing creates artificial incentives for end users to locate in gas-producing states where intrastate market gas is available. Also, because affected end users can avoid incremental pricing by getting off the pipeline system and purchasing gas directly from producers, incremental pricing artificially "tilts" affected end users toward carriage over utility sales and thereby distorts gas-to-gas competition.

Because of the reasons I mentioned above, A.G.A. believes it is in the best interests of our nation to repeal these artificial demand constraints. A.G.A. urges the members of this Subcommittee to take whatever actions are necessary in this regard.

2) OCS Leasing Moratoria Violate the Public Interest.

A.G.A. has long advocated the position that increased exploration and production in the Outer Continental Shelf (OCS) areas will increase the amount of natural gas that is domestically available. In turn, these supplies can be used to: 1) meet our nation's future energy needs; 2) help displace imported oil; 3) improve our nation's air quality; and, 4) reduce both the trade deficit and the Federal budget deficit.

Since 1982, approximately 53 million acres of OCS leasing areas have been withdrawn from oil and gas exploration by leasing moratoria. The main rationale for removing these areas from exploration was to protect these sensitive ecological areas from being damaged by offshore drilling.

Neither A.G.A. nor the gas industry as a whole questions the need for environmental safeguards in the development of the OCS areas. However, we believe that environmental considerations should help to guide such development, rather than being used as a justification for precluding such development completely.

As the members of this Subcommittee ponder the difficult questions regarding OCS natural gas development, A.G.A. hopes that the follwing facts will be kept in mind:

- Most of the energy produced from the OCS areas is natural gas, not oil. Natural gas accounts for two-thirds of current OCS production, and two-thirds of estimated OCS reserves.
- As I discussed earlier, natural gas is widely recognized as our cleanest burning primary fossil fuel, and emits virutally no SO^2 and only trace amounts of NO_x. It emits no lead, and is neither carcinogenic nor mutagenic. Therefore, it makes sense from an environmental standpoint to burn as much natural gas as possible. It is ironic that, under the guise of environmental protection, OCS leasing moratoria preclude otherwise attainable natural gas development and production, and therefore are counterproductive to the attainment of natural environmental policy goals.
- In the case of offshsore oil, the lesser energy component in the OCS areas, only .05% (five one hundredth of one

percent) of the world's oil pollution comes from U.S. offshore production. This compares with tanker operations and accidents (34.3%), municipal wastes (21.8%), and natural seeps (6.2%). Total spillage from U.S. offshore operations between 1975 and 1983 translates to less than one barrel spilled for every 140,000 barrels produced -- and less than one barrel spilled for every 2.1 Bcf of gas produced. In short, by decreasing the amount of hydrocarbons that are available from areas close to the U.S., we actually increase the risk of more devastating environmental damage to the world's oceans because we will then be forced to transport even more oil by tanker.

- The Potential Gas Committee estimates that fully 20 percent of our lower 48 state gas resource base lies in our offshore areas. The only way to prove that these resources exist in fact is to drill for them. To do this, it is especially important to provide for the long lead time involved in the development of offshore gas wells; sometimes it takes 10-15 years after initial discovery to establish peak production from offshore areas. Because gas supply projections assume substantial OCS resources, OCS gas is needed if we are to be sure of meeting our nation's future energy needs.
- Natural gas can and will play an important role in helping our nation to displace foreign oil imports. Furthermore, natural gas could play a strategic role in

protecting U.S. energy markets if an oil supply disruption occurs. If gas supply levels can be maintained at current levels, within one year of an oil supply disruption, gas could offset the loss of 730,000 barrels of oil per day -- or 17 percent of 1983 U.S. oil imports. If gas production was increased to its maximum potential, gas could, within five years, replace 1.8 million barrels per day -- over one-third of 1983 U.S. oil imports. However, increased OCS exploration and gas production would be crucial in developing this capability.

- Offshore energy production makes large contributions to the nation's Treasury. The revenue potential is not limited to "up-front" bonus bids for OCS leasing. Fully 75 percent of OCS revenues to the Federal Government comes from income taxes, windfall profits taxes, royalties, and rentals. Overall, the expected receipts from the OCS program for FY '86 are $8.3 billion. Together with the $2.1 billion generated from other Department of the Interior programs, this provides the second largest source of revenue to the Federal Government, after income taxes. Revenues of this magnitude cannot be ignored when searching for ways to reduce the Federal deficit. For these reasons, A.G.A. urges the members of the Subcommittee to support a balanced energy policy by refusing to renew and expand moratoria on OCS leasing.

3. Budget and Tax Issues

The 99th Congress is engaged in what may be the greatest Federal budget and tax reform movement since the Sixteenth Amendment to the Constitution took effect. I will now take a few moments to summarize briefly A.G.A.'s position on these important issues.

A) Budget Deficit

It is a widely accpeted fact that the Federal deficit must be reduced if our nation is to continue to have a vital and growing economy. However, the Congress must be diligent to ensure that the means used to reduce the deficit are not worse for the economy then the deficit is.

A.G.A. supports the proposition that spending reduction should be implemented prior to any proposals for tax increases, and that such reductions should equal or exceed any revenue increases proposed as a means of reducing the deficit.

B) Tax reform

With regard to the tax reform proposals, A.G.A. has determined that it can support the overall concept of a modified flat tax, provided that appropriate transitional rules and safeguards are written into the law. A.G.A.'s positions on specific provisions of the various tax reform plans include:

o Depreciation -- A.G.A. can support changes in depreciation deductions, provided that mandatory normalization is retained.

- Tax Credits -- A.G.A. opposes elimination of tax credits that provide production and capital formation incentives.
- Intangible drilling costs -- A.G.A. opposes repeal of current year expensing of these costs because such action would reduce incentives to drill for new gas. Considering our nation's reliance on imported oil, domestic energy production at optimal levels is in the national interest. Congress should take this into account when considering changes to present tax law.

4. DOE's Research and Development Budget

A.G.A. believes that Congress should redirect DOE's research activities to reflect the true value of the geosciences to our nation's energy needs. To this end, we recommend redirection of funds within the general sciences and basic energy sciences area. This redirection is intended to address the geosciences and resolve the research problems related to recovery of natural gas from the more exotic sources -- such as deep sources, methane hydrates, and geopressured zones.

In the past, DOE's R&D budget has focused on electric energy research, and almost ignored gas research. In fact, electricity-related research outranked gas research in last year's budget by a ratio of 15 to 1. Congress needs to reapportion current R&D funds to reflect more correctly the current energy needs of our nation.

CONCLUSION

The national interest requires that optimal natural gas production and use should be encouraged by the public sector. By and large, this is just a matter of getting the Federal Government out of the way of market forces. Such a policy posture can help America to improve its environment and reduce the Federal deficit. It would also help displace imported energy from unreliable and unstable nations.

The natural gas industry is dedicated to bring as much clean burning, economical, natural gas as possible to the people of our nation. We sincerly ask that Congress give us the freedom to meet this objective. We are willing to meet the challenge of the future. I challenge Congress today to give us the ability to meet these goals.

Thank you very much for allowing me to speak before you today. I will be happy to respond to your questions or comments.

ENERGY ANALYSIS

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PROJECTED ECONOMIC AND ENVIRONMENTAL IMPACTS OF RETAINING THE FUEL USE ACT THROUGH THE YEAR 2000

The prohibition on the construction of new gas-fired large industrial facilities and electric utility plants, as mandated by the Fuel Use Act (FUA) of 1978, impairs the ability of plant operators to produce goods and electricity in an optimal fashion with respect to cost, efficiency and environmental quality. FUA impedes the flexibility of plant operators, thereby limiting their creativity in meeting site-specific conditions via new technologies or through innovation. For example, the generation of electricity via new gas-fired combined cycle units (prohibited under FUA) would require capital expenditures of only about one-third those required for similarly sized new coal units, while producing virtually no sulfur dioxide or particulate matter.

This analysis projects that retaining FUA will restrict the volumes of gas delivered to large industrial facilities and electric utility plants by 3.0 quadrillion Btu (quads) annually by the year 2000. One scenario examined in the analysis assumes that this gas load loss will be offset by the construction and utilization of coal-fired facilities -- with a total incremental capital investment (over and above that required for gas equipment) of $44 billion ($1984) and additional costs to electricity consumers of up to $1.6 billion per year. In addition, even with required pollution control equipment the coal-based option would emit far more pollutants than the gas systems displaced, including 560,000 tons of sulfur dioxide per year, and 300,000 tons of particulate matter. (It should be noted that in the FUA repeal case domestic coal demand is projected to increase by approximately 70 percent by the year 2000 versus 83 percent with FUA retention.)

A second scenario -- one which is becoming increasingly more plausible -- is that electric utilities and industrial concerns will turn towards imported electric power and industrial goods rather than building domestic coal-based units. Were imports to offset the entire 3.0 quads of domestic gas consumption displaced, the U.S. gross national product would fall by as much as $127 billion in the peak impact year, and over 1.5 million domestic jobs would be lost by the year 2000.

1984 by the American Gas Association

PROJECTED ECONOMIC AND ENVIRONMENTAL IMPACTS OF RETAINING THE FUEL USE ACT THROUGH THE YEAR 2000

A. Introduction

The Fuel Use Act (FUA), passed in 1978, prohibits new electric utility plants and new large industrial facilities from using natural gas as their primary fuel. This legislation was enacted in a period when gas was in short supply -- a result of 25 years of Federal wellhead price regulation which acted to keep the price of gas below market clearing levels. Subsequent events have reversed this imbalance.

The purpose of this analysis is to examine the potential economic and environmental impacts of FUA through the year 2000. The impacts attributable to FUA retention are estimated under two possible scenarios. In the first, it is assumed that those new facilities which would be gas-powered in the absence of FUA will instead be fueled totally with coal. In the second scenario, it is assumed that the presence of FUA in conjunction with growing economic and environmental constraints on other fuel sources will result in reductions in domestic electrical production and industrial output. These reductions are assumed to be offset by increased imports of electricity and industrial products. The analysis also assumes that the FUA exemption process set up by the Department of Energy's Economic Regulatory Administration to reduce FUA impacts is partially effective for industrial cogeneration facilities and ineffective over time for electric utilities, consistent with recent experience.

B. Executive Summary

If the Fuel Use Act is not repealed, there will be serious negative consequences to the nation in terms of the cost of producing industrial goods and electricity, as well as the resultant pollution from these production processes. In addition, failure to repeal FUA will decrease domestic GNP while increasing unemployment and the trade deficit.

Coal Conversion Scenario -- based on the assumption that gas load loss attributable to FUA retention will be replaced by increased coal consumption. (It should be noted that FUA repeal would not significantly alter the strong predicted growth in coal demand. This analysis indicates a 70 percent growth in domestic coal demand by the year 2000 even with FUA repeal, versus 83 percent with FUA retention.)

- Failure to repeal FUA will result in a loss of 3.0 quadrillion Btu of annual gas load by the year 2000, with roughly 63 percent of this loss occurring in the industrial sector. (See Summary Table I.)

- Approximately 45,000 megawatts of coal-fired electric utility capacity and over 950 large industrial coal boilers would have to be constructed in order to offset the gas load loss, with a cumulative total incremental capital investment (over and above the investment needed for gas-based systems) of $44 billion (constant 1984 dollars).

- The cost of producing electricity in new scrubber-equipped coal units will exceed the cost of gas-powered combined cycle and cogeneration systems, and the incremental cost to electricity consumers is estimated to peak at $1.6 billion per year.

- The coal replacement option, even with required pollution control equipment for new facilities, would result in substantial incremental pollution: sulfur dioxide -- 560,000 tons per year (8.9 million tons cumulative between 1984 and 2000); particulates -- 300,000 tons per year (4.8 million tons cumulative); nitrogen oxide -- 360,000 tons per year (5.8 million tons cumulative); water pollution -- 30,000 tons per year (0.5 million tons cumulative); and solid wastes -- 24 million tons per year (383 million tons cumulative).

Import Scenario -- based on the assumption that declines in domestic production of electricity and industrial products due to reduced gas consumption will be offset by importing foreign goods and electricity.

- The prohibition of 3.0 quads of gas load would reduce the output of domestic industrial products and electricity, thus reducing the gross national product (GNP) as much as $127 billion per year (2.3 percent of projected total GNP) by the year 2000, with a cumulative impact of $1.16 trillion from 1984 through 2000. (See Summary Table II.)

- Decreased economic activity would increase domestic unemployment, reducing employment by 1.5 million workers (1.1 percent of projected total employment) by the year 2000.

- The U.S. trade deficit would be increased by an amount approximately equal to the GNP decrease -- $127 billion per year in 2000.

Summary Table I

PROJECTED IMPACTS OF RETAINING THE FUEL USE ACT, 1985-2000 -- COAL CONVERSION SCENARIO[1]

Gas Use Restricted (TBtu)[2]	Peak Year Impacts	Cumulative Impacts 1985-2000
Electric Powerplant	1,121	7,976
Large Industrial	1,903	18,183
Total	3,024	26,159
Incremental Capital Investment ($1984 Millions)		
Electric Powerplant	$1,480	$26,280
Large Industrial	3,260	17,420
Total	$4,740	$43,700
Incremental Cost of Electricity ($1984 Millions)		
Total	$1,553	$11,500
Incremental Pollution (Thousands of Tons)		
Sulfur Dioxide	1,068	8,940
Particulates	547	4,850
Nitrogen Oxides	670	5,790
Water Pollution	54	470
Solid Wastes	44,163	382,930

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1. Assumes gas use restricted by the Fuel Use Act is replaced by increased coal consumption.

2. Trillion Btu; 1000 TBtu = 1 Quadrillion Btu (Quad).

Sources: See Appendices I-III.

Summary Table II

PROJECTED IMPACTS OF RETAINING THE FUEL USE ACT, 1985-2000 -- IMPORT SCENARIO[1]

Gas Use Restricted (TBtu)[2]	Peak Year Impacts	Cumulative Impacts 1984-2000
Large Industrial	1,903	18,183
Electric Powerplant	1,121	7,976
Total	3,024	26,159
Decline in GNP ($1984 Millions)		
Large Industrial	$114,560	$1,068,180
Electric Powerplant	12,869	91,565
Total	$127,429	$1,159,745
Decline in Domestic Employment (Thousands of Workers)		
Large Industrial	273	1,369
Electric Powerplant	7	108
Total	280	1,477
Increase in Trade Deficit ($1984 Millions)		
Large Industrial	$114,560	$1,068,180
Electric Powerplant	12,869	91,565
Total	$127,429	$1,159,745

Note: Projected declines in GNP and employment due to retaining FUA account for 2.3 percent of total projected GNP in 2000, and 1.1 percent of total employment. See Appendices IV and V.

[1] Assumes decline in domestic production of electricity and industrial products due to restricted gas consumption is entirely offset by importing foreign goods and electricty.

[2] Trillion Btu; 1000 TBtu = 1 Quadrillion Btu (Quad).

Source: See Appendices IV and V.

C. Background

The Powerplant and Industrial Fuel Use Act (FUA) was passed in 1978 as one of the five legislative components of the National Energy Act. The purpose of FUA was to shift electric utility plants and major industrial fuel-burning installations (MFBI) from oil and natural gas to coal. FUA was largely a response to the: (1) Arab oil embargo of 1973 which highlighted the tenuous dependence on unstable imported oil sources; and, (2) the regulatory induced gas supply shortages of the mid-1970's. In contrast to oil, roughly one-third of which is supplied by foreign sources, only about 5 percent of our total natural gas supply is provided by imports, virtually all from Canada. However, nearly 25 years of Federal wellhead price regulation kept the price of gas below market clearing levels, thereby discouraging the exploration for, and production of, this energy source. A predictable situation of supply/demand imbalance for a commodity with a unresponsive and artificially low price -- natural gas -- was evident in the mid-1970's.

The Federal reaction to this market imbalance was twofold: (1) FUA was passed to limit the demand for gas; and, (2) the Natural Gas Policy Act (NGPA) was passed to stimulate the exploration for and development of new gas sources. The NGPA has provided the framework for a transition to a decontrolled gas market. The supply impetus provided by the NGPA has been both obvious and encouraging. The gas market went from shortages to surpluses, and natural gas reserve additions from 1980 through 1983 equaled 102 percent of gas production, compared to only 48 percent in the 1968-1978 period (excluding the one-year addition of the Prudhoe Bay, Alaska, discovery).

It has been argued by many that the restrictions imposed on electric utilities and large industrial plants by FUA were ill conceived, and that the success of NGPA in stimulating new gas supplies precludes the need to retain FUA. This opinion was given support in 1981 when a portion of FUA was repealed. "Existing" powerplants and MFBI (pre-1977) will not be required to be "off gas" by 1990 as mandated in the original legislation. However, new electric utility plants and MFBI (industrial boilers, cogenerators, turbines, or internal combustion engines with a fuel input capacity in excess of 100 MMBtu per hour) still may not use gas as a primary energy source.

Plant operators, not allowed to construct new gas-fired facilities, have a number of options available, including: nuclear or coal power, foreign imports, or postponing construction. However, each of these prospects has its risks. Electricity produced in this country via nuclear power has a well-known history of economic, regulatory, engineering, operating and construction delay problems. Postponing new construction is not a long-run option if the demand for electricity and industrial products is increasing, and fears have been expressed over the intermediate-term adequacy of both industrial and electric generating capacity. According to the U.S. Department of Energy, "the current excess of reserve capacity (electric) is likely to disappear by the end of the decade."[1] On the industrial side, manufacturers' capacity utilization reached 81.1 percent in March of 1984, the highest level in four years. Utilization factors above 83 to 86 percent are thought to be inflationary, and it is feared that some industries have already exceeded that point.[2] Thus, new productive capacity will be required.

Coal-based electricity can, in some instances, be a relatively costly energy alternative. Coal facilities are not only expensive to construct and operate, but they also require significant expenditures for the control of sulfur dioxide, particulates, sludge and other pollutants. The environmental problems associated with coal combustion are receiving increasing national attention in light of the ongoing debate on appropriate national sulfur dioxide emission levels.

The importation of electric power and industrial products can also be substituted for domestic gas use in these markets, but this strategy has negative impacts in terms of domestic employment, gross national product (GNP), and the balance of trade deficit. Proof of the need for concern over this option is provided by the fact that imported electricity from Canada is projected to increase from 17,802 gigawatt-hours in 1981 to 35,000 gigawatt-hours in 1995, and, as a result, five coal-fired powerplants in the northeastern U.S. (3,518 megawatts) have been cancelled recently.[3]

D. Methodology and Assumptions

This analysis examines the potential consequences of retaining FUA under two alternative scenarios. The first assumes that new facilities which would have been gas-fired are instead powered by coal. The second scenario was constructed under the assumption that MFBI and electric utilities would import electricity and industrial products in order to offset their reduced output resulting from displaced gas demand. Obviously, in reality the response would be some combination of these two options, but the proportional shares are non-quantifiable. Thus, for the purposes of this analysis it was assumed that the response would be uniform.

1. FUA Exemption Assumptions

It is possible for electric utility powerplants and MFBI to be exempted from FUA restrictions under certain circumstances. This analysis was prepared under a "worst case" scenario with respect to electric utility powerplants and MFBI boilers -- it was assumed that the FUA exemption process is effectively inoperative. That is, it was assumed that the exemption process would not work as a result of either stringent regulatory enforcement policy, or the fear of plant operators of becoming involved in costly and time-consuming exemption procedures with the ultimate outcome unknown. (Some would argue that FUA does not hinder plant-operator flexibility in constructing new facilities because of the exemption process. Obviously, if this is true, there is no need to retain FUA and its cumbersome filing requirements.)

This "worst case" assumption for utility powerplants and MFBI boilers is based on the fact that, according to the most recent Powerplant and Industrial Fuel Use Act Annual Report,[4] no exemptions were granted to electric utility powerplants in 1983, and only one permanent exemption was granted for an MFBI boiler to be fueled primarily by gas or oil. Exemptions were granted to 17 industrial cogeneration facilities, technically considered powerplants under FUA, presumably because they sell more than half of their cogenerated electricity to the grid. In addition, three electric utility powerplants, considered MFBI under a technicality of FUA, were granted temporary exemptions to burn oil in boilers for heat and testing purposes while in the process of converting to coal.

The exemption process for MFBI cogeneration facilities (included in the industrial sector in this analysis) was assumed to be partially effective -- it was assumed that exemptions would be granted for one-half of all potential gas-fired MFBI cogenerators. An additional 50,000 megawatts of cogenerated power could be added by the year 2000, according to General Energy Associates for the U.S. Department of Energy.[5] Based on filings with the Federal Energy Regulatory Commission from 1980 through 1983, roughly 50 percent of new cogeneration facilities are gas-fired. Thus, 25,000 megawatts of gas-fired cogeneration potential in the year 2000 was assumed (one-half of 50,000), and three-fourths of this amount (18,750 megawatts) was assumed to be MFBI size based on information contained in the DOE cogeneration report cited above. Exemptions from FUA were assumed to be granted for 9,375 megawatts of the 18,750 megawatt total MFBI gas-fired cogeneration potential. Failure to repeal FUA would force a load loss of 317 trillion Btu per year in 2000 for the remaining 9,375 megawatts.

2. Coal Conversion Scenario

This scenario assumes that gas load prohibited by Fuel Use Act would be replaced by increased coal consumption.

a. The projected volumes of gas sold to electric utility powerplants through the year 2000 were provided by the A.G.A. Total Energy Resource Analysis demand/marketplace model (A.G.A.-TERA) which was run twice, once assuming retention of FUA (DM8364C)and once assuming its repeal (DM8363I). (See Appendix I for projected gas volumes, and Appendix VI for a further description of the A.G.A.-TERA model.) The difference in gas volumes indicated by the two runs represents the utility powerplant gas load prohibited by FUA. (A.G.A.-TERA, developed and maintained by A.G.A., is a series of models which provides a detailed simulation of the gas industry with consideration of the environment in which the industry operates.)

b. Gas sales to MFBI were also obtained from the A.G.A.-TERA model for the FUA repeal case. Gas sales to MFBI, assuming a retention of FUA, were estimated to decline at a rate of 3 percent per year due to retirements, consistent with a boiler life of 35 years. (See Appendix I for projected volumes.) The quantitative extent to which actual 1984 gas sales are lower than they would have been without the FUA is subject to analytical debate due to: (1) the extent to which FUA exemptions have been granted, and (2) the non-quantifiable extent to which facilities owners have been unwilling to even consider gas in view of the regulatory burden and uncertainty associated with obtaining an exemption. Consequently, to be conservative, MFBI gas consumption was assumed to be essentially the same in the FUA and non-FUA cases in 1984, as were gas sales to the powerplant sector. This assumption understates the impact which the Fuel Use Act has had to date.

In the coal conversion scenario, FUA retention case, prohibited cogeneration gas load was offset by coal-fired powerplants for electricity production and coal boilers for industrial steam raising. The cogeneration system applied in the analysis was a gas turbine system which converts 25 percent of the input energy to electricity and 45 percent to process steam. See: Office of Technology Assessment, Industrial and Commercial Cogeneration.[6]

c. The additional, or incremental, cost of constructing coal-fired powerplants instead of gas facilities was estimated by multiplying the gas load loss times an installed capital cost differential of $800 per kilowatt (kw) of capacity (constant 1984 dollars). This differential represents the cost of constructing a new pulverized coal facility ready for operation in 1990 -- approximately $1,300 per kw -- versus $500 per kw for a gas-fired combined cycle unit. A capacity factor of 60 percent was assumed for the powerplants, which were sized at 328 megawatts (Mw) each. The cost of producing electricity from the coal unit would exceed the cost of producing electricity from the gas-fired combined cycle unit by 8 mills per kwh (levelized cost assuming nominal gas prices increasing from \$5.70 to \$11.89 per MMBtu from 1985-2000, and coal prices of \$2.05 to \$6.13 per MMBtu). Installation and production costs were obtained from Burns and Roe Inc., A Preliminary Assessment of the Modular Block Power Plant Concept.[7]

d. The MFBI investment differential for coal versus gas boilers was estimated at approximately \$18 million per boiler (constant 1984 dollars) -- \$23 million for a 280 MMBtu per hour coal unit with required pollution control equipment, operating at 65 percent capacity, versus \$5 million for a comparably sized gas unit. Costs were obtained from ICF, Inc., Economic Considerations in Industrial Boiler Fuel Choice.[8] A capacity of 280 MMBtu per hour is the average size of gas boilers over 100 MMBtu per hour according to PEDCO Environmental, Inc., Population and Characteristics of Industrial/Commercial Boilers in the U.S.[9]

e. The incremental pollution attributable to coal-fired electric plants and MFBI was estimated using the same facility sizes and operating conditions as described above. Emissions from MFBI and powerplants, each assumed to be equipped with pollution control equipment required to meet New Source Performance Standards, were assumed to be equal per Btu of fuel consumed. Emissions were based on 2 percent sulfur, 10 percent ash coal. Control equipment removal efficiencies of 90 percent for sulfur dioxide and particulates, and 35 percent for nitrogen oxides, were assumed for coal units. Pollutant emissions per MMBtu input for sulfur dioxide, particulates and nitrogen oxides were obtained from the U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors.[10] Solid waste and water pollution estimates were derived from Hittman Assoc., Inc., Environmental Impacts, Efficiency and Costs of Energy Supply and Use.[11]

The relative emissions of gas turbine cogeneration versus coal boilers for generating electricity and industrial process steam were obtained from the Office of Technology Assessment, Industrial and Commercial Cogeneration.[6]

3. Import Scenario

This scenario assumes that the decline in domestic production of electricity and industrial products due to prohibited gas consumption would be entirely offset by importing electricity and foreign goods, respectively.

a. The gas load loss for powerplants and MFBI in the import scenario is the same as that projected for the coal conversion scenario.

b. The powerplant gas load loss through the year 2000 was converted to a domestic electricity output loss, and then multiplied by the cost of producing electricity in a new coal-fired unit -- $28 per MMBtu in constant 1984 dollars for a plant coming on-line in 1990. See: Burns and Roe, Inc., Preliminary Assessment of the Modular Block Power Plant Concept.[12] The resultant marginal value represents the decline in domestic Gross National Product (GNP) attributable to importing electricity as opposed to producing it domestically.

c. Importing industrial goods reduces GNP by the value of the goods, including the value of the fuel, materials, labor and capital used to produce the goods. (The value of the fuel used to produce electricity in the powerplant example discussed above is included in the value of the final product; a value-added approach was used in the MFBI estimation procedure, and the values of fuel input and product output -- excluding fuel -- were determined separately.) The industrial gas load prohibited by the Fuel Use Act was multiplied by constant-dollar industrial gas prices as projected by the A.G.A.-TERA model to obtain the fuel input value. The product value was estimated based on the ratio of the value of fuel input to product output for those industries which account for the bulk of gas sales to industrial boilers. A weighting factor for this ratio was developed based on the sales of gas boilers by standard industrial classification sold from 1965 through 1977 shown below. (Source: PEDCO Environmental, Inc., Population and Characteristics of Industrial/Commercial Boilers in the U.S.[13])

Distribution of Gas Boilers Sold from 1965 through 1977

Industry	Percent Share
Chemicals and Allied Products	25.4%
Food and Beverages	16.2
Petroleum Refining	12.8
Other Manufacturing	9.0
Stone, Clay, Glass	7.0
Paper and Allied Products	6.9
Textiles	6.8
Primary Metals	5.4
Transportation	5.0
Fabricated Metals	4.5
Wood Products	1.0
Total	100.0%

The weighted average of the value of the fuel input to the final product output is roughly 9 percent, based on the above weights and fuel input/product output ratios contained in the A.G.A.-TERA model.

d. The loss in domestic employment under the import scenario was determined on the basis of the estimated declines in the value of powerplant and industrial output (discussed above), and the projected value added per employee as found in Wharton Econometric Forecasting Assoc., Wharton Long Term Alternative Scenarios and 20-Year Extension.[14] The weighted average (as above) value added per employee is approximately $58,000 per employee in 1985 for the MFBI segment, increasing to $75,000 by 1995 (constant 1984 dollars). Value added per employee is roughly 60 percent greater for the powerplant segment.

e. Importing electricity and industrial goods from abroad would increase the U.S. trade deficit by the value of the products imported, equal to the GNP loss indicated above.

4. Additional Factors Not Incorporated in Analysis

This analysis quantifies only direct economic impacts in the import scenario. Indirect economic impacts of the Fuel Use Act, such as reduced demand for consumer goods due to the loss of employment in the import scenario, were not considered. Therefore, the economic impacts cited here represent a conservative underestimate of the actual economic costs of the Fuel Use Act under this scenario. In addition, certain other factors were not considered in this analysis because they were felt to be of minimal consequence, including the following:

a. An increase in domestic gas consumption of 3.0 quads under FUA repeal would require increased supplies from various sources -- domestic sources (approximately 2 quads), Canadian imports (approximately one-half quad), and other supplemental sources (approximately one-half quad).

b. The average burner tip cost of gas would increase slightly (approximately 4 cents per MMBtu) due to greater gas use, increased gas acquisition costs being largely offset by greater transmission and distribution system capacity utilization factors. This increase in transportation efficiency would reduce per unit gas transmission and distribution charges for all customers.

c. The impacts on the U.S. balance of payments of the increase in Canadian gas imports were not considered. Maximum one-year impacts were estimated to be less that $2 billion (equivalent to less than 1.5 percent of the total peak-year imports from Canada under the import scenario) and would be at least partially offset by reciprocal Canadian trade.

d. In addition, the value of the U.S. dollar was held constant between scenarios. The huge balance of payments deficit created by FUA could reduce the value of the U.S. dollar in international currency exchanges. Such a change in the value of the dollar could mitigate some of the trade balance deficits created by FUA but could also fuel domestic inflation.

E. Results of Analysis

1. Coal Conversion Scenario

Under the assumptions of the coal conversion scenario, powerplant gas consumption would fall from the projected 1985 level of 3.2 quadrillion Btu (quads) to 2.2 quads in the year 2000, while an increase to 3.3 quads is projected absent FUA. (See Appendix I.) The large industrial gas consumption estimates (including cogeneration gas demand) with and without FUA are 0.7 and 2.6 quads, respectively. Approximately 0.8 quads of the 1.9 quad industrial load loss (i.e., non-gain) is attributable to cogeneration load loss. Thus, the combined industrial and electric utility estimated load loss in the year 2000 is 3.0 quads. It should be noted that even with FUA repeal, domestic coal demand is projected to increase by 70 percent from 1985-2000, compared to 83 percent otherwise.

The shifting of 3.0 quads of gas load to coal-fired powerplants and industrial facilities would entail an incremental capital expenditure of $44 billion (all costs stated in constant 1984 dollars, see Appendix II). The shift would necessitate the construction of roughly 45,000 megawatts of coal-fired capacity, at an incremental cost exceeding $26 billion. In addition, large industrial coal boilers with an incremental price of nearly $18 billion would be required. Incremental expenditures would peak in 1988 at approximately $4.7 billion. The incremental cost of producing electricity in pulverized coal-electric plants versus combined cycle gas cogeneration units would total $11.5 billion through the year 2000, peaking at $1.6 billion in the final year.

Even when equipped with flue gas desulfurization systems, precipitators and other pollution control devices, coal combustion is appreciably more polluting than gas combustion. (See Appendix III.) Natural gas combustion produces virtually no sulfur dioxide (SO_2), particulate matter (TSP), or solid wastes, and significantly less nitrogen oxides (NO_x) and water pollution than coal combustion. The incremental emissions attributable to FUA through the year 2000 were estimated at: SO_2 -- 8.9 million tons (1.1 million tons per year peak); TSP -- 4.9 million tons (0.5 million tons peak); NO_x -- 5.8 million tons (0.7 million tons peak); water pollution -- 0.5 million tons (0.1 million tons peak); and, solid wastes -- 383 million tons (44 million tons peak).

2. Import Scenario

The gas load loss in the import scenario is identical to that projected in the coal conversion scenario, reaching 3.0 quads by the year 2000. The total cumulative loss in GNP attributable to FUA was estimated at $1,160 billion, with a peak annual loss of $127 billion in 2000. The loss is split between large industrials and powerplants in an 85:15 ratio. (It should be noted that the secondary detrimental impacts to GNP, which may significantly outweigh the primary impacts, were not included in this analysis.) The electricity and industrial products not produced domestically would be imported, and the increase in the trade deficit would equal the GNP reduction.

Nearly 1.5 million domestic jobs would be lost under the import scenario, nearly 1.4 million industrial jobs, and over 100 thousand in the electric utility sector. Again, secondary job losses were not estimated in this analysis.

F. Conclusions

Based on the information presented in this analysis, it is clear that retaining the Fuel Use Act will have serious consequences in terms of the cost of producing industrial goods and electricity, as well as the resultant pollution from these production processes. In addition, retaining FUA will decrease domestic GNP while increasing unemployment and the trade deficit.

The analysis certainly does not suggest that all new electric powerplants and large industrial boilers should be gas-fired. The choice of an energy source is site specific, and it must be made on the basis of plant engineering, site geography, the local fuel market, and other factors which may be known only to the plant operator. It is a complex choice which cannot effectively be made by legislators or regulators. Plant operators need the utmost in terms of flexibility in making their plant energy decisions, as such flexibility encourages efficiency and creativity -- FUA blocks this flexibility.

Footnotes

1. U.S. Department of Energy, The Future of Electric Power in America, (Washington, DC: June, 1983) p. ES-26.

2. The Washington Post, "Factory Use Increases in March," (Washington, DC: April 17, 1984) p. C-6.

3. The Energy Daily, "Imported Power from Canada Knocks Coal Out of Northeast," (Washington, DC: May 22, 1984) p. 3.

4. U.S. Department of Energy, Economic Regulatory Administration, Powerplant and Industrial Fuel Use Act Annual Report, (Washington, DC: March, 1984).

5. General Energy Assoc. for the U.S. Department of Energy, Industrial Cogeneration Potential (1980-2000) Targeting of Opportunities at the Plant Site, (Washington, DC: May, 1983) p.7.

6. U.S. Office of Technology Assessment, Industrial and Commercial Cogeneration, (Washington, DC: February, 1983) p. 286.

7. Burns and Roe, Inc. A Preliminary Assessment of the Modular Block Power Plant Concept, (Arlington, VA: April, 1984) p. 5.

8. ICF, Inc., Economic Considerations in Industrial Boiler Fuel Choice, (Washington, DC: June, 1978) p. II-68.

9. PEDCO Environmental, Inc. for the U.S. Environmental Protection Agency, Population and Characteristics of Industrial/Commercial Boilers in the U.S., (Research Triangle Park, NC: August, 1979) p. 11.

10. U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors, (Research Triangle Park, NC: August, 1982).

11. Hittman Assoc. Inc. for the Council on Environmental Quality, Environmental Impacts, Efficiency, and Costs of Energy Supply and Use, (Washington, DC: November, 1974).

12. Burns and Roe, Inc., Op. Cit. p. 5.

13. PEDCO Environmental, Inc., for the U.S. Environmental Protection Agency, Op. Cit., p. 28.

14. Wharton Econometric Forecasting Assoc., Wharton Long Term Alternative Scenarios and 20-Year Extension, (Philadelphia, PA: January, 1984) p. 55.

    A.G.A. is a member of Wharton Econometric Forecasting Associates U.S. economic forecasting services. These are available on an annual subscription basis. For information, please contact Mr. J.V. Heimark, Director of Marketing, Wharton EFA, 3624 Science Center, Philadelphia, Pa 19104, (215) 386-9000.

Appendix I

PROJECTED GAS LOAD LOSS ATTRIBUTABLE TO FUEL USE ACT, 1985-2000
(Trillions of Btu)

	Electric Powerplant[1]			Large Industrial[3]			
Year	With FUA	No FUA	FUA Load Loss	With FUA[2]	No FUA[1]	FUA Load Loss	Total Industrial and Utility Load Loss
1985	3,160	3,160	0	1,085	1,101	16	16
1986	3,032	3,045	13	1,053	1,224	171	184
1987	3,005	3,060	55	1,021	1,497	476	531
1988	3,022	3,141	119	991	1,772	781	900
1989	3,023	3,229	206	961	1,955	994	1,200
1990	3,009	3,267	258	932	2,078	1,146	1,404
1991	2,943	3,295	352	904	2,126	1,222	1,574
1992	2,846	3,270	424	877	2,049	1,172	1,596
1993	2,749	3,243	494	851	2,032	1,181	1,675
1994	2,644	3,230	586	825	2,078	1,253	1,839
1995	2,555	3,232	677	800	2,158	1,358	2,035
1996	2,470	3,247	777	776	2,244	1,468	2,245
1997	2,385	3,261	876	753	2,331	1,578	2,454
1998	2,314	3,283	969	731	2,409	1,678	2,647
1999	2,256	3,305	1,049	709	2,495	1,786	2,835
2000	2,199	3,320	1,121	682	2,585	1,903	3,024

Sources: 1. American Gas Association, A.G.A.-TERA Model, Scenarios DM8364C and DM8363I (Arlington, Va: July, 1984).

2. Large gas boiler life of 35 years assumed, i.e., gas boilers retired at a rate of approximately 3% per year.

3. Includes cogeneration load loss (0.8 TBtu in 2000).

Appendix II

PROJECTED INCREMENTAL CAPITAL INVESTMENT AND ELECTRICITY PRODUCTION COST REQUIRED TO COMPENSATE FOR FUEL USE ACT, 1985-2000

($1984 Millions)

	Incremental Capital Investment			
Year	Industrial Investment[1]	Powerplant Investment[2]	Total Investment	Incremental Cost of Producing Electricity[2]
1985	$528	$784	$1,312	$51
1986	828	429	1,257	77
1987	3,247	1,137	4,384	145
1988	3,260	1,480	4,740	232
1989	2,202	1,862	4,064	340
1990	1,580	1,147	2,727	409
1991	666	1,928	2,594	521
1992	260	1,600	1,860	615
1993	300	1,629	1,929	711
1994	340	2,062	2,402	832
1995	380	2,098	2,478	954
1996	295	2,126	2,421	1,081
1997	825	2,146	2,971	1,207
1998	844	2,086	2,930	1,329
1999	898	1,918	2,816	1,443
2000	967	1,848	2,815	1,553
	$17,420	$26,280	$43,700	$11,500

Sources: 1. Industrial load loss from Appendix I times the differential cost of constructing large (280 MMBtu/hr) coal versus gas boilers ($18 MM per unit). Includes investment required for coal-fired boilers to offset steam raising capacity of cogenerators precluded by FUA. See: ICF Inc., Economic Considerations in Industrial Boiler Fuel Choice, (Washington, DC: June,1978).

2. Powerplant load loss from Appendix I times the differential cost of constructing pulverized coal versus combined cycle gas powerplants ($800/kw). Includes investment and electricity production cost for coal-based powerplants to offset electrical production capacity of cogenerators precluded by FUA. See: Burns and Roe, Inc., Preliminary Assessment of the Modular Block Power Plant Concept, (Arlington, VA: April, 1984) p.5. Incremental cost of electrical production based on a 8 mill/kwh differential (from same source) at a 60% capacity factor.

Appendix III

PROJECTED INCREMENTAL POLLUTION ATTRIBUTABLE TO FUEL USE ACT, 1985-2000

(Thousands of Tons Per Year)

Year	Sulfur Dioxide[1]	Particulates[1]	Nitrogen Oxides[1]	Water Pollution[2]	Solid Wastes[2]
1985	71	3	22	2	1,270
1986	103	20	43	3	2,680
1987	197	93	118	10	7,750
1988	291	171	198	16	13,140
1989	374	234	262	22	17,512
1990	429	275	307	25	20,492
1991	484	308	344	28	22,973
1992	516	305	350	29	23,309
1993	562	313	369	30	24,454
1994	627	340	406	33	26,849
1995	702	374	450	35	29,704
1996	772	413	496	40	32,777
1997	842	450	542	44	35,821
1998	914	486	585	48	38,646
1999	988	518	628	51	41,390
2000	1,068	547	670	54	44,163
	8,940	4,850	5,790	470	382,930

Sources:

[1] Industrial and powerplant boiler data from: U.S. Environmental Protection Agency, Compilation of Air Pollutant Emission Factors (Research Triangle Park, NC: August, 1982). Based on 2% sulfur, 10% ash coal; 90% removal of SO_2 and TSP, 35% removal of NO_x. Emissions differential for gas turbine cogeneration versus coal boilers for equivalent steam and electricity production from: U.S. Office of Technology Assessment, Industrial and Commercial Cogeneration, (Washington, DC: February, 1983) p. 286.

[2] Hittman Assoc. Inc. for the Council on Environmental Quality, Environmental Impacts, Efficiency and Costs of Energy Supply and Use, (Washington, DC: November, 1974).

Appendix IV

PROJECTED DECLINE IN GNP ATTRIBUTABLE TO FUEL USE ACT, 1985-2000

($1984 Millions)

Year	Electric Powerplant Output[1]	Large Industrial Fuel Input	Large Industrial Value-Added Output[2]	Industrial and Powerplant Total[3]	Projected Total GNP[4]
1985	0	$78	$831	$909	$3,809,004
1986	$148	797	8,883	9,828	3,829,344
1987	630	2,104	24,728	27,462	3,999,748
1988	1,366	3,405	40,573	45,344	4,112,522
1989	2,366	4,314	51,638	58,318	4,225,974
1990	2,962	4,974	60,944	68,880	4,244,506
1991	4,040	5,597	64,986	74,623	4,418,526
1992	4,866	5,626	62,327	72,819	4,537,854
1993	5,670	5,775	62,806	74,251	4,658,086
1994	6,728	6,252	66,635	79,615	4,786,906
1995	7,773	6,899	73,957	88,629	4,808,376
1996	8,922	7,619	79,947	96,488	5,021,042
1997	10,058	8,363	85,938	104,359	5,154,608
1998	11,124	9,095	91,384	111,603	5,287,722
1999	12,043	9,879	97,266	119,188	5,427,616
2000	12,869	10,923	103,637	127,429	5,571,126
	$91,565	$91,700	$976,480	$1,159,745	$73,892,960

Sources:

1. Powerplant load loss from Appendix I converted to an electrical output loss, and multiplied by levelized revenue requirement of $28 per MMBtu for a new coal-fired powerplant (completed in 1990). See Burns and Roe, Inc., Preliminary Assessment of the Modular Block Power Concept, (Arlington, VA: April, 1984). Includes value of fuel input as an intermediary good.

2. Decline in industrial value-added output per unit decline in fuel input from A.G.A.-TERA Model, Scenario DM8363I, (Arlington, VA: July, 1984).

3. Total projected decline in GNP resulting directly from FUA-induced decline in electricity production, in industrial output (net of purchased fuels), and in production of fuels used by industrial production.

4. As projected by Wharton Econometric Forecasting Assoc., Long-Term Alternative Scenarios and 20-Year Extension, (Philadelphia, PA: January, 1984).

Appendix V

PROJECTED DECLINE IN DOMESTIC EMPLOYMENT ATTRIBUTABLE TO FUEL USE ACT, 1985-2000
(Thousands of Workers)

Year	Large Industrial	Electric Powerplant	Total Decline	Projected Total Employment
1985	14	0	14	106,780
1986	153	2	155	106,800
1987	426	7	433	109,910
1988	699	14	713	111,800
1989	889	25	914	113,520
1990	920	28	948	114,030
1991	981	38	1,019	116,860
1992	941	46	987	118,620
1993	948	54	1,002	120,410
1994	1,006	64	1,070	122,030
1995	977	65	1,042	122,240
1996	1,056	75	1,131	124,670
1997	1,135	84	1,219	126,180
1998	1,207	93	1,300	127,640
1999	1,285	101	1,386	129,110
2000	1,369	108	1,477	130,600

Source: Employment per unit of output and total projected employment obtained from: Wharton Econometric Forecasting Assoc., Wharton Long-Term Alternative Scenarios, Philadelphia, PA: January, 1984). Decline in output from Appendix IV.

Appendix VI

A.G.A.-TERA MODEL

The A.G.A.-TERA (Total Energy Resource Analysis) system of computer models is a detailed long-run simulation of natural gas supply, transportation, and markets. The model was developed and is maintained by the American Gas Association, under the guidance of a gas industry advisory committee -- the A.G.A.-TERA Advisory Committee. Complete model documentation is available from A.G.A.

The A.G.A.-TERA system is best visualized in five major parts: gas and oil exploration and production industry; gas utility industry; alternative energy marketing industries including electric utilities; marketplace interaction; and end-use consumer demands. Each major part is comprised of one or more sub-models. (See exhibit VI-1)

Prices and supplies of alternative fuels including distillate oil, residual oil, coal and electricity are calculated in a series of sub-models. To generate results, each sub-model uses historical data and user-specified scenario assumptions regarding raw material, processing and transportation costs, and market conditions.

The oil market simulation begins by combining the domestic crude oil supplies and prices obtained from the supply models with user specified imported crude oil prices to form a composite refinery acquisition cost of crude oil. The refinery acquisition cost is then added to regionalized refinery markups, which represent refining costs and transportation costs, to generate retail residual and distillate oil prices.

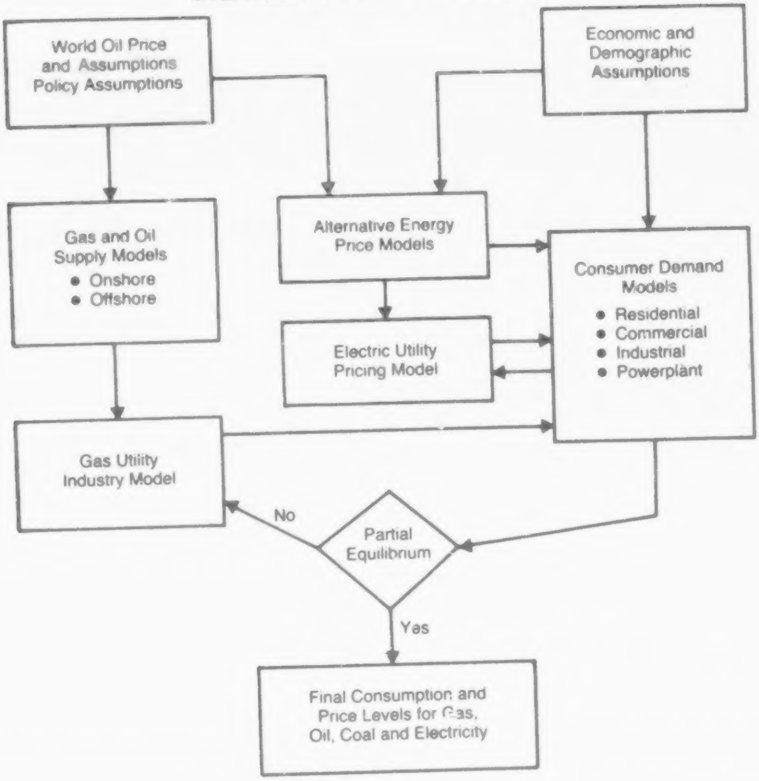
Two options exist for the calculations of these refining markups. The model can either use historical levels of markups plus inflation and user-specified real growth rates reflecting increasing capital and operating costs, or the user can specify a market-driven retail price for oil products as a proportion of the crude oil price and back-calculate the required refinery markups.

The coal market simulation begins with the historical regional minemouth price of coal. These prices are escalated by inflation and a real rate of cost growth, specified by the scenario, which reflects increases in production costs.

The model then looks at the patterns of transporting of coal from producing regions to consuming regions. The weighted average minemouth price of coal consumed in each region is calculated from the prices of coal in each producing region and the proportion of coal consumed from each producing region.

The transportation and marketing costs are simulated for each region and each class of service to provide the final component of retail coal prices. These costs are derived from historical data escalated at the rate of inflation plus scenario specified real growth

EXHIBIT VI-1



OVERVIEW OF A.G.A.-TERA SYSTEM

World Oil Price and Assumptions Policy Assumptions
Economic and Demographic Assumptions
Gas and Oil Supply Models
• Onshore
• Offshore
Alternative Energy Price Models
Electric Utility Pricing Model
Consumer Demand Models
• Residential
• Commercial
• Industrial
• Powerplant
Gas Utility Industry Model
No
Partial Equilibrium
Yes
Final Consumption and Price Levels for Gas, Oil, Coal and Electricity

rate and added to the minemouth price of coal consumed. The real rates of escalation are specific to the region and class of service.

Electricity prices are projected by A.G.A.-TERA through simulation of the aggregate components of traditional public utility cost-of-service methods. These components include:

- Debt and equity charges to carry net depreciated investments and capital;
- O&M cost, taxes, and depreciation;
- Fuel costs of energy consumed by fuel type in electricity generation.

Regional aggregate inventories of powerplant capacity and net electric plant by fuel type are maintained by the model for this process. Required capacity additions, determined by demand for electricity, augment the inventory of powerplants. Capital costs of additions to capacity are detailed by type of plant constructed (e.g., dual gas/coal-fired, single coal-fired, nuclear, etc.), historical capital costs of powerplants by fuel type and the real cost escalation of powerplant construction.

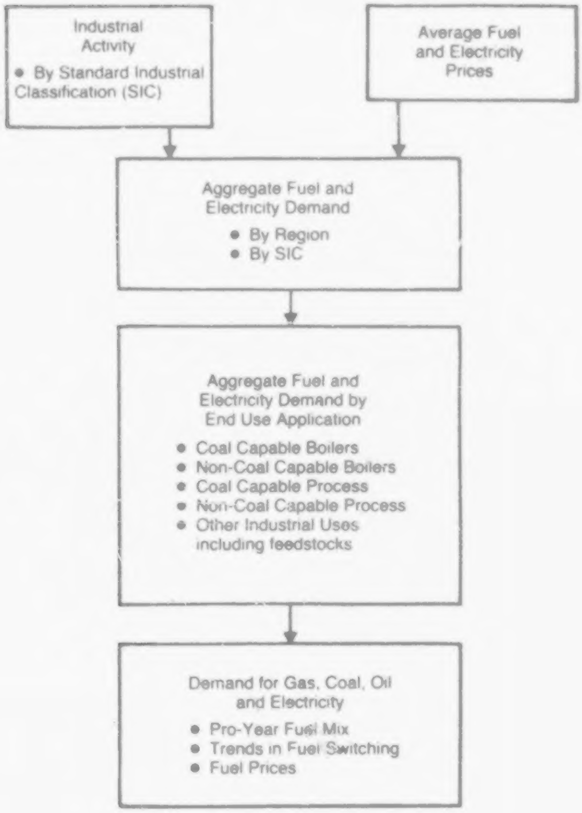
The annualized costs of the net electric powerplant for each region are estimated based on financial considerations such as utility debt to equity ratio, cost of debt, required return on equity, operating capital, etc. The annual operating costs, which include fuel handling cost, taxes, and depreciation, in addition to traditional operating and maintenance costs, are calculated by plant type and aggregated to regional totals. The final component of total annualized cost -- the fuel cost -- is determined by capacity and capacity utilization factors of each plant type.

The total annualized cost of powerplant operation is converted to a per-unit cost of electricity by dividing by the volumes of electricity sold to final consumers. At this point, the price of electricity to residential, commercial and industrial consumers is determined based on historical electric utility ratemaking ratios.

The industrial energy demand submodel in A.G.A.-TERA considers demands for fuels, demands for feedstocks, and demands for purchased electricity. Each type of demand is estimated separately. Demand for fuel is estimated individually for ten key manufacturing SICs and for aggregates of other manufacturing SICs and other non-manufacturing individual SICs. These fuel demands are then further subdivided for each group into boiler, non-boiler, coal-capable, and non-coal-capable end-uses. Total fuel demands are broken out by fuel type in each end-use using a combination of prior-year fuel choice and price induced fuel switching. Demands for purchased electricity also are estimated individually for the same group of ten manufacturing SICs and two aggregate groups of other manufacturing and non-manufacturing SICs. Demands for metallurgical coal, feedstock oil, and feedstock (and other unclassified but feedstock-related) gas are estimated for the appropriate SICs.

EXHIBIT VI-2

A.G.A.-TERA
INDUSTRIAL ENERGY DEMAND


Industrial Activity
● By Standard Industrial Classification (SIC)
Average Fuel and Electricity Prices
Aggregate Fuel and Electricity Demand
● By Region
● By SIC
Aggregate Fuel and Electricity Demand by End Use Application
● Coal Capable Boilers
● Non-Coal Capable Boilers
● Coal Capable Process
● Non-Coal Capable Process
● Other Industrial Uses including feedstocks
Demand for Gas, Coal, Oil and Electricity
● Pro-Year Fuel Mix
● Trends in Fuel Switching
● Fuel Prices

Determination of projected electric utility fuel demand begins with computed demands for electricity from the residential/commercial and industrial sub-models. Regional electricity consumption is adjusted by net interregional electricity sales movement. Projected powerplant capacity (broken down by seven categories of fossil fuel plants plus hydro and nuclear) is based on utilization rates and changes in plant capacity caused by retirement of old plants, replacement plants coming on-line and increasing electricity demand. Electrical generation by fossil fuels (as opposed to nuclear and hydro generation) is determined and fossil fuel demands (for each type of fossil fuel plants) are estimated by market share equations similar to those used in industrial demand.

The runs used in this analysis were relatively minor modifications of the A.G.A.-TERA Fall 1983 Base Case. A full description of the Fall 1983 Base Case was published November 16, 1983, and is available from A.G.A.

The specific assumptions underlying this forecast (i.e., assuming no repeal of the Fuel Use Act) include the following:

- Natural gas wellhead prices were assumed to follow the NGPA schedule.

- The national average refinery acquisition cost of crude oil was assumed to be $28.50 per barrel in 1983 and 1984 (measured in 1983 dollars), rising at a 1% real annual rate in 1985 and a 2% real annual rate thereafter.

- The national average price of residual fuel oil in the industrial sector was assumed to rise from 78% of the price of crude oil (refiner acquisition cost) in 1983, to 81% of the price of crude oil by 1985, and 90% by 1990.

- Projected rates of economic growth and inflation were taken from the economic projections reported in A.G.A.'s Five Year Economic Outlook.[1] In particular, the number of households is projected to grow at an average annual rate of 1.8% from 1983 through 1993, with real personal income per household growing at an average annual rate of 1.0%. Real output from manufacturing is projected to increase at a 3.5% annual rate and inflation is expected to average 4.5% per year during this period. The A.G.A. economic projection was extended to the year 2000 using growth rates projected by Wharton Economic Forecasting Associates, Inc. in Wharton Long-Term Forecast Extension to the Year 2002 (Philadelphia: August 1983).

To estimate the energy impacts of Fuel Use Act repeal, the base case was run without the Fuel Use Act prohibitions in place. This allowed the model to simulate the demand for gas in the industrial and power plant sectors that would arise in the absence of Fuel Use Act restrictions.

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[1] Five Year Economic Outlook (Arlington, VA: American Gas Association, June 24, 1983).

Senator NICKLES. Thank you very much, Mr. Lawrence.

Senator Ford, did you have any comments that you wanted to make at this point?

Senator FORD. No, thank you.

Senator NICKLES. Senator Hecht, did you?

Senator HECHT. No, thank you, Mr. Chairman.

Senator NICKLES. Well, we appreciate your attendance.

Mr. Elam.

STATEMENT OF JACK ELAM, VICE PRESIDENT AND GENERAL COUNSEL, CONE MILLS CO., AND CHAIRMAN, PROCESS GAS CONSUMERS GROUP

Mr. ELAM. Thank you, Mr. Chairman, Senator Hecht, Senator Ford.

I, too, have a summary of our prepared statement.

I'm Jack Elam vice president and general counsel of Cone Mills Corp., and chairman of the Process Gas Consumers Group.

Cone Mills is a textile company, Mr. Chairman, and if you would like some standard of comparison about competition in reference to Mr. Terpstra's statement, we routinely lose or gain business over 1-eighth of a cent. So we know what competition is in the textile business.

The Process Gas Consumers Group is an organization of the 18 large industrial consumers of natural gas listed in attachment one of our prepared statement.

PGC appreciates this opportunity to offer its views on the state of today's natural gas market. From our perspective as industrial users, there are two paramount issues: one, security of supply; and, two, price.

As to supply security, we remain skeptical that natural gas will be efficiently distributed in a market that remains partially regulated under the NGPA. Mr. Lawrence's remarks reminded me with a sense of deja vu of early 1977, when the chairman of the board of our local distribution company was assuring us we had plenty of gas, and 48 hours later they called up and said we had to shut down our plants.

As to price, we are willing to pay free market prices for gas, but we are strongly opposed: one, to paying prices higher than the free market, or, two, paying a disproportionate share so that other gas consumers can be subsidized, such as through so-called incremental or marginal pricing schemes.

PGC last appeared before this committee in March 1983, more than 2 years ago. At that time, we noted that many of our members were energy-intensive companies, that spent as much as $200 million per year for their natural gas needs, and that we had seen a 20- to 30-percent increase in our gas bills in the previous year. That was 1982.

We further noted that the market in 1983 was characterized by wildly disparate prices, some far below market clearing, and others absurdly above it. Because of take-or-pay problems, high cost supplies were being produced before lower cost supplies, which drove off industrial load, distorted signals sent back to producers as to future gas needs, and set the stage for potential future shortages.

Indeed, drilling in 1982, had been sharply reduced below 1981 levels.

We urge this committee to give priority to comprehensive legislation that would: One, remove all wellhead price controls in 2 years; two, provide a market-oriented resolution of the contract problem; three, repeal the incremental pricing and the Fuel Use Act; four, provide expanded access to natural gas supplies for all parties.

We concluded, "Now is the time to stop trying to run the marketplace from Washington and to call an end to all wellhead price regulation once and for all. Price regulation didn't work for oil, it didn't work for the economy as a whole, and it isn't working for natural gas.

What has changed since March 1983?

Well, in the intervening months, Congress tried and failed to enact a comprehensive legislation that PGC and many members of this subcommittee advocated. We lost a major opportunity to deregulate all natural gas, to open up access to all consumers, to repeal onerous demand restraints on industrial fuel choices. As a result, the market we are facing today retains many of the problems that we spoke about in 1983.

There have been two significant changes. First, additional wellhead supplies were deregulated on January 1 of this year, substantially reducing the percentage of gas subject to distorting wellhead price controls. This occurred, we might add, without the fly-up of natural gas prices that many predicted would occur.

Second, and, in our view, more important, the issue of nondiscriminatory transportation of natural gas emerged as a major issue in the gas debate of 1983-84.

Contract carriage, or the requirement that pipelines transport on a nondiscriminatory basis gas owned by others, has become the major solution to the problems of today's gas market.

For the past 2 years, PGC and other industrial groups have been pointing out that interstate pipelines and many distribution companies have tended to act as obstacles to the operation of competitive forces that would smooth out price and supply distortions resulting from the NGPA.

There is ample public evidence that pipelines and, in many cases, distribution companies, act as bottlenecks to prevent or limit competition in their service areas. We cite them in our written statement, Mr. Chairman.

These pipelines and distribution companies have protected their own sales from competition by denying transportation services to those who would like to buy gas from competing third parties. The annual cost to an industrial company of being denied access to available, competitively priced gas, can easily run into the millions of dollars. The American Iron and Steel Institute has estimated that the steel industry alone could save one-quarter of a billion dollars if it were afforded nondiscriminatory access to transportation services for gas purchased directly from producers.

For a single major steel company, the amount that could have been saved in 1983 was $40 million.

As a result of these unnecessary extra costs, plants have been closed with consequent unemployment, jobs continue to be lost to overseas competition—and, as you know, we in the textile business know something about that, also—millions of dollars have been invested in otherwise uneconomic equipment to reduce reliance on pipeline supplies, production has been shifted from one region to another to reduce gas costs, with resulting adverse economic effects in the high gas cost regions, and some users have even constructed duplicating pipeline facilities of their own, or hired a trucking company to avoid having to rely on recalcitrant traditional suppliers.

Unfortunately, shielded from competition and protected by regulation, interstate pipelines have seemed almost oblivious to these problems.

We agree wholeheartedly with the Department of Energy's statement that "Constraints on spot market eligibility and limitations on access to pipeline capacity support discriminatory actions by pipeline companies that slow the downward adjustment of prices across all segments of the natural gas market."

DOE's position favoring contract carriage is supported not only by industrial users, but also by a vast array of parties representing many different and competing interests, including the equal access group independent producers, the NASUCA residential consumer advocates, and the Heritage Foundation.

Nondiscriminatory carriage, including carriage for process uses, is essential to restoring and maintaining market balance and increasing gas sales competition. Such competition will give consumers and producers market options that do not exist when a handful of pipelines use their monopoly power to control the purchase and sale of natural gas.

Producers will be better able to sell gas and consumers will get lower prices when there are surplus supplies and a reduced risk of harmful curtailments when supplies are tight.

Pipelines and local distribution companies should have higher overall deliveries, albeit greater competition in their role as sellers. Without this, the system remains dependent on the buying decisions of pipelines and local distribution companies which have been sheltered by regulatory agencies from economic loss, from curtailments, or price induced sales declines.

Proposals such as those of the American Gas Association for "voluntary contract carriage" are inherently inadequate because pipelines and distributors have shown that they will use their monopoly power over transportation to limit competition with their own sales.

As stated, the 98th Congress failed to enact contract carriage legislation, and the Federal Energy Regulatory Commission, until recently, continued to refuse to use its authority aggressively to promote competition.

Although transportation for others has expanded over the past 2 years, pipelines have volunteered to transport only when it suits their own interests in displacing another energy seller, and much of this transportation has been for other pipelines.

The SMPs and other discount rate programs have done little or nothing to lower prices for so-called captive markets—that's us.

The need for broader gas transportation received a major boost on May 30, 1985, when the FERC issued an extensive notice of proposed rulemaking which, if approved and implemented, will sharply redirect the natural gas industry toward nondiscriminatory transportation services and far greater competition than it has ever known.

The NOPR reflects many of the arguments PGC and others, such as the DOE, have made in favor of increased price competition and nondiscriminatory transportation services in the natural gas industry. While FERC does not propose to mandate open gas transportation, it attempts to make nondiscriminatory transportation policies sufficiently attractive and the alternatives sufficiently unattractive, that pipelines will voluntarily accept the overall package of procompetitive proposals.

In general, PGC is satisfied with the FERC's proposal.

We believe that FERC has authority under the Natural Gas Act to prohibit undue discrimination, and has responded to other requirements, such as those of the Outer Continental Shelf Lands Act, to promote competition.

We will, of course, be commenting in substantial detail to the FERC, but we have provided the general comments to the subcommittee in our written statement, including: One, the requirement of part A that pipelines not discriminate in transportation is essential. It is required by economic analysis, sound regulatory policy, and legal precedent.

Two, the proposal correctly would require participating pipelines to offer firm transportation. We will be recommending that this be extended to interruptible service, and that incentives be provided for LDC's—that's local distribution companies and not lesser developed countries—that incentives be provided for LDC's to offer transportation.

Senator **Ford**. Well, you might as well file for that, too, with the Federal Government. [General laughter.]

Mr. **Elam**. Why, if you'll permit us, we'll so file. [General laughter.]

Senator **Ford**. The way you're talking, you might qualifiy.

Mr. **Elam**. We're on the way. [General laugher.]

Three, the FERC correctly proposes to eliminate restrictions on sources of gas to be transported. For example, OCS gas should be available to any willing buyers.

Finally, the part D proposals for separate pricing of old and new gas, one, are unnecessary to achieve the overall procompetitive purposes of the NOPR, and, two, carry with them many unintended, but adverse, side effects.

Rather than achieving its goal of levelling the playing field for pipelines—which seems to be a popular phrase in Washington these days—the commission would actually multiply the number of regulatory levels in the playing field and then shift responsibility for dealing with them to State and local authorities.

PGC will be urging the FERC to adopt more effective alternative procedures to part D for advancing the goal of increasing fair competition.

If we can get them ready in time, we'd like to file our comments on the NOPR with you also.

Senator **Nickles**. We'd appreciate it.

In conclusion, of course the NOPR is only a proposal. The FERC can make modification before a final rule is promulgated this fall. And it cold retreat from the stand it has proposed to take.

In addition, even if FERC stands firm, the pipelines or other parties may refuse to accept this redirection of the marketplace toward nondiscriminatory transportation services and resist the proposal's implementation.

Thus, we would urge this subcommittee carefully to monitor through its oversight authority the progress of the FERC's effort and to be prepared if this bold initiative falls short of creating a more competitive, stable, and open gas market, to step in and take corrective action.

This concludes our prepared statement.

[The prepared statement of Mr. Elam follows:]

PGC
PROCESS GAS CONSUMERS GROUP • SUITE 800/1666 K STREET N.W.
WASHINGTON, D.C. 20006
202 887-3425

BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

STATEMENT OF
JACK ELAM
ON BEHALF OF
THE PROCESS GAS CONSUMERS GROUP

July 11, 1985

BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

STATEMENT OF THE PROCESS GAS CONSUMERS GROUP

I am Jack Elam, Vice President and General Counsel of Cone Mills Company and Chairman of the Process Gas Consumers Group.

The Process Gas Consumers Group (PGC) is an organization of eighteen large industrial consumers of natural gas organized to promote the development and adoption of coordinated, rational, and consistent federal and state policies with respect to gas use. Representing many of the nation's basic industries, our member companies own and operate hundreds of plants in virtually every state and purchase natural gas directly or indirectly from both interstate and intrastate pipelines, with most of our facilities on the interstate system. A list of our members is included as Attachment 1.

PGC appreciates this opportunity to offer its views on the state of today's natural gas market.

I. PGC's Perspective

PGC members consume natural gas in many applications but our statement today reflects primarily our use of natural gas in industrial processes for which alternate, non-gaseous fuels cannot reasonably or technically be utilized. From our perspective, there are two paramount natural gas issues: (1) security of supply and (2) price.

Supply security means to us the ability of consumers to depend upon their suppliers to satisfy their gas requirements. Neither current supply surpluses nor optimistic gas resource forecasts give industrial users any significant comfort, because we remain skeptical that those resources will be efficiently produced and distributed in a market that remains partially-regulated under the NGPA.

Natural gas prices, as with other inputs into the manufacturing process, presents costs which must be recovered by companies in the prices charged for their products. We are willing to pay free market prices for gas, but we are strongly opposed to (1) paying prices higher than those which would be commanded in a truly free market, and (2) paying a disproportionate share of gas costs so that other gas consumers can be subsidized, such as through so-called incremental or marginal cost-based pricing schemes. We believe that rates should be based on the cost of providing service. As consumers, operating in competitive national and international markets, we cannot tolerate the impact of artificially high gas prices on our businesses.

PGC last appeared before this Committee in March of 1983, more than two years ago. At that time we noted that many of our members were energy intensive companies that spent as much as $200 million per year for their natural gas needs and that we had seen a 20%-30% increase in our gas bills in the previous year. We further noted that the market in 1983 was characterized by wildly disparate prices at the wellhead -- some far below "market clearing" and others absurdly above it. Some pipelines experienced industrial load losses caused by the purchase of expensive supplies under strict take-or-pay provisions which shut off cheaper supplies. High cost supplies were being produced before lower-cost supplies, which further depressed demand, distorted the signals sent back to producers as to future gas needs, and was setting the stage for potential future shortages. Indeed, drilling in 1982 had been sharply reduced below 1981 levels.

In March of 1983, we urged this Committee to give priority to legislation that would deal boldly and comprehensively with the problems then facing the gas industry and gas consumers. We advocated the adoption of a comprehensive bill containing provisions to (1) remove wellhead price controls from all natural gas in two years, (2) provide a market-oriented resolution of the much-discussed "contract problem" through insertion of market-out rights in all existing contracts, (3) repeal the incremental pricing program and the Powerplant and Industrial Fuel Use Act, and (4) provide expanded access to natural gas supplies by all pipelines, distribution companies, and end-users.

We concluded that "[n]ow is the time to stop trying to run the marketplace from Washington and to call an end to all wellhead price regulation once and for all. Price regulation didn't work for oil; it didn't work for the economy as a whole; and it isn't working for natural gas."

II. The Gas Marketplace Today

What has changed since March of 1983? Well, in the intervening months, Congress tried and failed to enact the comprehensive legislation that PGC and many members of this Subcommittee advocated. We lost a major opportunity to deregulate all natural gas, to open up access to all consumers legislatively, and to repeal onerous demand restraints on industrial fuel choices. As a result, the gas market today retains most of the problems that we spoke about in 1983 - pipelines continuing to purchase expensive gas with many pipeline sales rates higher than the marketplace would permit, with barriers remaining to user access to lower-priced supplies, and with continued constraints on industrial use of natural gas.

There have, of course, been two significant changes. First, additional wellhead supplies were deregulated on January 1 of this year, substantially reducing the percentage of gas subject to distorting wellhead price controls. This occurred, we might add, without the "fly-up" of natural gas prices that many predicted would occur.

The second, and in our view more important change is that, because of the failure to achieve complete wellhead deregulation, the issue of nondiscriminatory transportation of natural gas has emerged as a major issue in the gas debate of 1983-84. As a result of partial deregulation, combined with the Commission's restrictive interpretation of NGPA §601(c)(2) standard of "fraud, abuse or similar grounds," the Commission's traditional ratemaking role has been reduced to allocating costs, designing rates, and reviewing the reasonableness of only approximately 20% of a pipeline's total costs. As a result, direct price competition among gas sellers is the only mechanism that can keep in check a pipeline's costs. Thus, contract carriage, or the provision of transportation services on a nondiscriminatory basis of gas owned by others, has in our view, become the major element that can rectify the problems of today's gas markets.

For the past two years, PGC and other industrial groups have pointed out, in legislative and regulatory forums, that interstate pipelines and many distribution companies have tended to act as obstacles to the operation of competitive forces that would smooth out price and supply distortions resulting from the NGPA. Because their facilities are essential to delivering gas to their customers, interstate pipelines and distribution companies have the power to act as bottlenecks to prevent or substantially limit meaningful gas price competition within their service areas. There is ample public evidence that pipelines, and in many cases distribution companies, have not hesitated in the past two years to exercise that power to protect their vested interest in preventing competition. These pipelines and distribution companies have implemented policies to protect their own sales from competition by denying transportation services to those who would like to buy gas from competing third parties.

In some cases, the policies have been established in public documents, as the following examples illustrate:

- Columbia Gas Transmission Corporation's filed tariffs in 1983 explicitly banned transportation for users whenever Columbia decides that the transported gas would compete with its own sales. The lawfulness of these and other anticompetitive restrictions was challenged and the issue remains pending, in Docket No. RP84-11, nearly two years after the tariff sheets took effect. Columbia Gulf Transmission Company incorporates into its tariffs all of Columbia Gas' transportation restrictions.

- Transcontinental Gas Pipe Line Corporation freely admitted in testimony in a FERC proceeding, Docket No. RP83-137-000, that it will not transport gas for any end user if such transportation will compete with its own sales. Experience confirms that this is Transco's consistent policy.

- A witness for Tennessee Gas Pipeline Company testified in Docket No. RP82-125 that Tennessee will not transport gas sold by others if such transportation would reduce its own sales. Tennessee subsequently modified its policy, but then imposed a rate penalty designed to prevent anyone from displacing Tennessee's own sales.

- Texas Eastern Transmission Corporation has end user transportation tariffs which limit such services to instances involving displacement of oil. Texas Eastern's policy was partly a product of distributors' desires for protection from competition. Although the reasonableness of that restriction was challenged well over a year ago, in Docket No. RP83-35-000, the issue is still pending at FERC.

- Montana Dakota Utilities Company's filed tariffs stating as a condition of service that "gas transported hereunder shall not be used to displace volumes of gas that would otherwise be purchased from [MDU]," _i.e._, it will not transport gas that will compete with its own sales. FERC approved that tariff in Docket No. RP83-14-001, _et al_., over a major producer's objection to that limitation on competition.

- Panhandle Eastern Pipeline Company imposes, as a condition of transportation, a "bid out" procedure which gives its existing producer-suppliers a right of first refusal to supplant another producer's sale upon matching the major contract terms. Transco imposes a similar condition.

- Numerous local distribution companies also refuse to transport any gas except to displace alternate fuels, and they pressure pipelines in FERC proceedings and elsewhere to do the same.

In addition, a number of pipelines and local distribution companies have erected insuperable barriers to competition even though they have not formally announced a policy against transporting competing gas supplies. The following examples illustrate this point:

- In the course of more than a year's negotiations, an interstate pipeline repeatedly found excuses for not transporting specific supplies of gas to a midwestern company, despite proposals for gas to be delivered from various locations. The company finally announced that the relevant plant would be closed, putting 500 people out of work. The high cost of gas was a major contributing factor to the shutdown.

- A midwestern manufacturer negotiated the purchase of self-help gas to replace an alternate fuel. The interstate pipeline and local distribution company agreed to transport the gas for the manufacturer. After completing one year of the contract, the interstate pipeline refused to continue the transportation on the grounds that the LDC was delivering gas to its industrial customers at a lower price than the alternate fuel. This cost relationship between the LDC-delivered gas and the alternate fuel had existed from the initiation of the contracts. Yet, the interstate pipeline seized on this fact to "justify" eliminating gas-to-gas competition.

- A midwestern steel company that purchases natural gas directly from an interstate pipeline has an oil equalization agreement with the pipeline whereby the gas price matches low sulfur fuel oil to the degree the industrial has "installed" equipment to burn oil. In spite of this, the pipeline has steadfastly refused to transport gas for any of its customers in spite of numerous requests by the steel company and others.

- An industrial user in the East found gas available for direct purchase from a producer and its local distribution company agreed to transport the gas to the user's plant. Two of the interstate pipelines serving the area refused to carry the gas because the user could not certify it would displace an alternate fuel.
- Complaints have been filed with the Pennsylvania PUC by local distribution companies to prevent industrial users from shifting to another utility for gas supply. With overlapping service areas between utility companies, this request would eliminate all gas-to-gas competition and force industrial customers into situations of being required to purchase gas at noncompetitive prices.

The economic consequences of users being denied access to available, competitively priced gas can be profound, and the annual cost to individual industrials can easily run into the millions of dollars. The American Iron and Steel Institute has estimated that the steel industry alone could save one quarter of a billion dollars ($250,000,000) if it were afforded nondiscriminatory access to transportation services for gas purchased directly from producers. For a single major steel company, according to members of the House of Representatives Committee on Energy and Commerce, the amount that could have been saved in 1983 was $40 million. As a result of these unnecessary extra costs, some plants have been closed with consequent unemployment; steel jobs continue to be lost to overseas competition; millions of dollars have been invested in otherwise uneconomic equipment to reduce reliance on pipeline supplies; production has been shifted from one region to another to reduce gas costs, with resulting adverse economic effects in the high gas cost regions; and some users have even constructed duplicative pipeline facilities of their own or hired a trucking company to avoid having to rely on recalcitrant, traditional suppliers. Homeowners and commercial gas users have likewise taken substantial steps to reduce their demand permanently. Indeed, the cost of idle capacity on some pipelines is becoming a significant rate problem in itself, threatening to compound the problem of high underlying gas costs. Unfortunately, shielded from competition and protected by regulation, interstate pipelines have seemed almost oblivious to these costs and the permanent erosion of markets.

We agree wholeheartedly with the statement by the Department of Energy in its Second Report to Congress that "[c]onstraints on spot market eligibility and limitations on access to pipeline capacity support discriminatory actions by pipeline companies that slow the downward adjustment of prices across all segments of the natural gas market." Department of Energy, Increasing Competition in the Natural Gas Market, January 1985, p. S-5. DOE's position favoring contract carriage is supported not only by industrial users, but also by a vast array of parties representing many different and often competing interests, including the Equal

Access Group (independent producers), the NASUCA (residential consumer advocates), and the Heritage Foundation.

Nondiscriminatory carriage, including carriage for process uses, is essential to restoring and maintaining market balance and increasing gas sales competition. Such competition will give consumers and producers market options that do not exist when a handful of pipelines use their transportation monopoly power to control the purchase and sale of natural gas. Those market options will translate into better opportunities for producers to sell gas and more market-responsive wellhead and retail prices. Consumers will get lower prices when there are surplus supplies and a reduced risk of harmful curtailments when supplies are tight. Individual producers will have more buyers to deal with. Pipelines and local distribution companies should have higher overall deliveries, albeit greater competition in their role as sellers. Without expanding the opportunities for users and producers to do business directly, the system remains dependent on the buying decisions of pipelines and local distribution companies, which historically have been sheltered by regulatory agencies from economic losses from curtailments or price-induced sales declines. Sellers that are sheltered from the economic impact of marketing and supply errors cannot be expected to buy their gas supplies efficiently. Gas-on-gas competition is needed. This will induce lower prices and contract renegotiation in the short term (1) by giving users direct access to lower priced sellers and (2) by increasing market pressure on high priced sellers.

Proposals, such as those of the American Gas Association, for "voluntary" contract carriage are inherently inadequate because pipelines and distributors have shown that they will use their monopoly power over transportation to limit competition with their own sales.

Although transportation for others has expanded over the past two years, pipelines have volunteered to transport only when it suits their own interests in displacing another energy seller, and much of this transportation has been for other pipelines. Special marketing programs (SMPs) clearly illustrate this pattern and, as we have previously stated, the DOE Report provides many specific examples of pipelines consistently refusing (either subtly or explicitly) to transport natural gas that will compete with their own sales. Many distributors do the same.

The 98th Congress failed to enact contract carriage legislation, and the Federal Energy Regulatory Commission (FERC) until recently continued to refuse to use its authority aggressively to promote competition. Thus, many high priority industrial and other consumers who lack economical alternate fuel capabilities have continued to be denied the opportunity to obtain the economical supplies of natural gas that should be available in the marketplace. The SMPs and other discount rate programs have done little or nothing to lower prices for so-called "captive" markets or to promote the gas price competition that is badly needed to bring about voluntary contract renegotiation. Those programs primarily focus on only 25 percent of the market -- that is, those industrial users with installed residual oil capabilities -- and most gas consumers are still victims of pipelines' uncompetitive sales rates. Indeed, by affording high-priced pipelines and producers the opportunity to increase their deliveries and revenues without having to make across-the-board price reductions, the SMPs have tended to prop up prices at artificially high levels.

III. Recent FERC Activitity

The marketplace's need for broader gas transportation received a major boost on May 30, 1985 when the FERC issued an extensive Notice of Proposed Rulemaking (NOPR) which, if approved and implemented, will sharply redirect the natural gas industry toward nondiscriminatory transportation services and far greater competition than it has ever known. It is a direct outgrowth of FERC's three-phase Notice of Inquiry proceeding in Docket No. RM85-1-000, which was initiated by notices issued December 24, 1984 and January 18, 1985, and it responds to the recent decisions of the United States Court of Appeals for the D.C. Circuit which vacated portions of the Blanket Certificate and Special Marketing Programs. Maryland Peoples Counsel v. FERC, Nos. 84-1019 and 84-1090 (May 10, 1985).

The NOPR reflects many of the arguments PGC and others, such as the DOE, have made in favor of increased price competition and nondiscriminatory transportation services. While FERC does not propose to mandate open gas transportation, it attempts to make nondiscriminatory transportation policies sufficiently attractive (and the alternatives sufficiently unattractive) so that pipelines will voluntarily accept the pro-competitive proposals. For example, Part A of the NOPR proposes to replace all existing blanket transportation authorizations with new programs which are specifically conditioned to prohibit discrimination against any class of potential customers. In exchange for agreeing to provide open transportation, pipelines would become eligible both for certain take-or-pay relief (Part B) and for a new "optional certificate" procedure (Part C) which would make it significantly easier for pipelines to initiate new competitive services and to attach new customers.

In general, PGC is most satisfied with the FERC's proposal. We believe that FERC has acted well within its authority under the Natural Gas Act to prohibit undue discrimination and has responded to other requirements, such as those of the Outer Continental Shelf Lands Act, to promote competition. We will, of course, be commenting in substantial detail to the FERC, but we would offer the following general comments on the NOPR to the Subcommittee:

o The nondiscrimination requirement of Part A is essential. It is required by economic analysis, sound regulatory policy, and legal precedent. However, end users should not be limited to successive 120-day terms for authorized transportation, as proposed in the NOPR. FERC does not propose to limit the terms allowed LDC shippers under §311 and it would discriminate against end users to give them no more than four months certainty at a time that their gas will be transported.

o The proposal correctly would require participating pipelines to offer *firm* transportation. However, we will be urging the FERC also to require participating pipelines to offer interruptible transportation service at rates reflecting costs and the quality of service.

o With respect to the proposed modifications of the transportation regulations under NGPA §311, FERC has correctly proposed: (a) to eliminate the "system supply test" so that transportation can be performed for individual end users' accounts; (b) to require intrastate pipelines that perform §311 services to perform such services without discrimination; and (c) to continue to treat as nonjurisdictional those facilities that are constructed only to provide transportation under §311.

o The provisions of Part A allowing sales customers to reduce their contract demand levels by 25% per year make sense even if there is a risk that a pipeline will abandon that portion of its sales service obligation to an LDC. However, it is important that the economics of sales services be sufficiently attractive to pipelines so that they have incentives to offer sales services to customers that wish to switch from transportation back to sales.

o FERC correctly proposes to eliminate restrictions on the sources of gas to be transported (*e.g.*, OCS gas should be available to any willing buyers), but the Commission, in some cases, will have to approve abandonments of committed gas supplies, including OCS gas. Freely permitting abandonments (at least temporary abandonments) will also be important to achieving widespread take-or-pay settlements, as the Commission seeks to encourage under Part B.

- The Commission should create incentives for LDCs to offer transportation. For example, distributors might be deemed ineligible for the benefits of the program (e.g., the right to reduce their contract demands and to receive blanket transportation) unless they offer nondiscriminatory transportation to their customers.

- Despite PGC's support for FERC's intended goal in Part D to rid the gas market of any significant distortions still caused by remaining price controls, PGC believes that the Part D proposals for separate pricing of "old" and "new" gas (1) are unnecessary to achieve the overall pro-competitive purposes of the NOPR and (2) carry with them many unintended, but seriously adverse, side-effects. Rather than achieving its goal of "levelling the playing field" for pipelines, the Commission would actually multiply the number of levels in the playing field and then shift responsibility for dealing with them to state and local authorities. In attempting to address a perceived cushion "problem" whose significance has already been greatly reduced at the pipeline level, FERC would recreate at the distributor level both the cushions themselves and the competition-distorting problems associated with them. Thus, PGC and others will urge FERC to retain rolled-in pricing, to eliminate Part D as written, and to adopt more effective alternative procedures for advancing the goal of increasing fair competition.

IV. Conclusion

Of course the NOPR is only a proposal. The FERC can make modifications before a final rule is promulgated this Fall, and it could retreat from the stand it has proposed to take in favor of more competition and improved availability of lower cost supplies for consumers. In addition, even if FERC stands firm, the pipelines or other parties may refuse to accept this redirection of the marketplace toward nondiscriminatory transportation services and resist the proposal's implementation. Thus, we would urge this Subcommittee, carefully to monitor through its oversight authority the progress of the FERC's effort and to be prepared, if this bold initiative falls short of creating a more competitive, stable and open gas market, to step in and take corrective action.

This concludes our prepared statement. We will be happy to answer any questions the Subcommittee may have.

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April 19, 1985

PROCESS GAS CONSUMERS GROUP
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Attachment 1

Senator FORD. Mr. Chairman.

Senator NICKLES. Senator Ford.

Senator FORD. As happens to us a great deal of the time, they're waiting on me at another committee at 10 o'clock, so I am a little bit late. But I do have some questions for several members of this panel, and if I'm unable to return, I'd like to ask permission to submit questions to the members of the panel and would ask for an expeditious response.

Senator NICKLES. Certainly, certainly.

We appreciate your participation.

Senator FORD. Thank you, and I'll try to get back.

Senator NICKLES. You bet.

Mr. Sheehy.

STATEMENT OF EDWARD J. SHEEHY, VICE PRESIDENT, PRODUCTIVITY MANAGEMENT AND OPERATING SERVICES, HERCULES, INC., ON BEHALF OF THE PETROCHEMICAL ENERGY GROUP, ACCOMPANIED BY GORDON GOOCH, COUNSEL

Mr. SHEEHY. Thank you, Mr. Chairman.

I can summarize PEG's concerns about the Commission's rulemaking by posing four basic questions.

First, is it likely that the problems caused by the cushion of cheap, forever regulated, gas will be solved by the simple expedient of transferring the cushion from the control of companies regulated by the Federal Government to companies regulated by State governments and the creation of a new Federal entitlements program?

We think the answer to this is no.

We have had considerable experience with other Federal entitlements programs, and, in our view, they have all been a disaster. And the cushion program is not solved merely by creating a new Federal entitlements program.

Second, is it likely that a nondiscriminatory, firm, transportation system, open to all shippers, will result if priority is given to local distribution companies who, in turn, are not required to offer transportation service in exchange for the benefits of the program as both the inter- and intrastate pipelines are? We think the answer to this is no, and that the nondiscriminatory transportation program may be illusory.

Third, is it likely that all producers will be willing to give to the pipelines the discretion to shut in production for the remainder of the delivery obligation just for a small fraction of projected payments? We think the answer again is no, and that the take-or-pay proposal is unlikely to work.

Fourth, is it likely that the prospects for a long-term gas supply will improve, or at least stay the same? We are in serious doubt about this. We remember curtailments.

The NOPR says in one place that the new rate structure, "Should serve to lower gas prices in the second block." If this is true, then it will not be because of market forces, but, rather, because of Federal regulation.

In the past, Federal regulations affecting gas prices at the wellhead have led to curtailments.

If you will examine chart 1, which is on the easel in front of you, you will see that the cushion problem does not disappear; that the block 1 gas is a real plum for those who are lucky enough to get an entitlement, and that, contrary to the Commission's intention, there is no level playing field.

If INGAA is correct, compare a price of $2.50 to $2.70 per mcf in the spot or new gas market with the block 2 gas prices particularly on different pipelines.

We have not commented here on the uncertainties, legal and otherwise, which the rulemaking creates.

Our counsel, Mr. Gooch, and I will be pleased to address any questions.

Thank you very much for the opportunity to be heard.

[The prepared statement of Mr. Sheehy follows:]

The Petrochemical Energy Group
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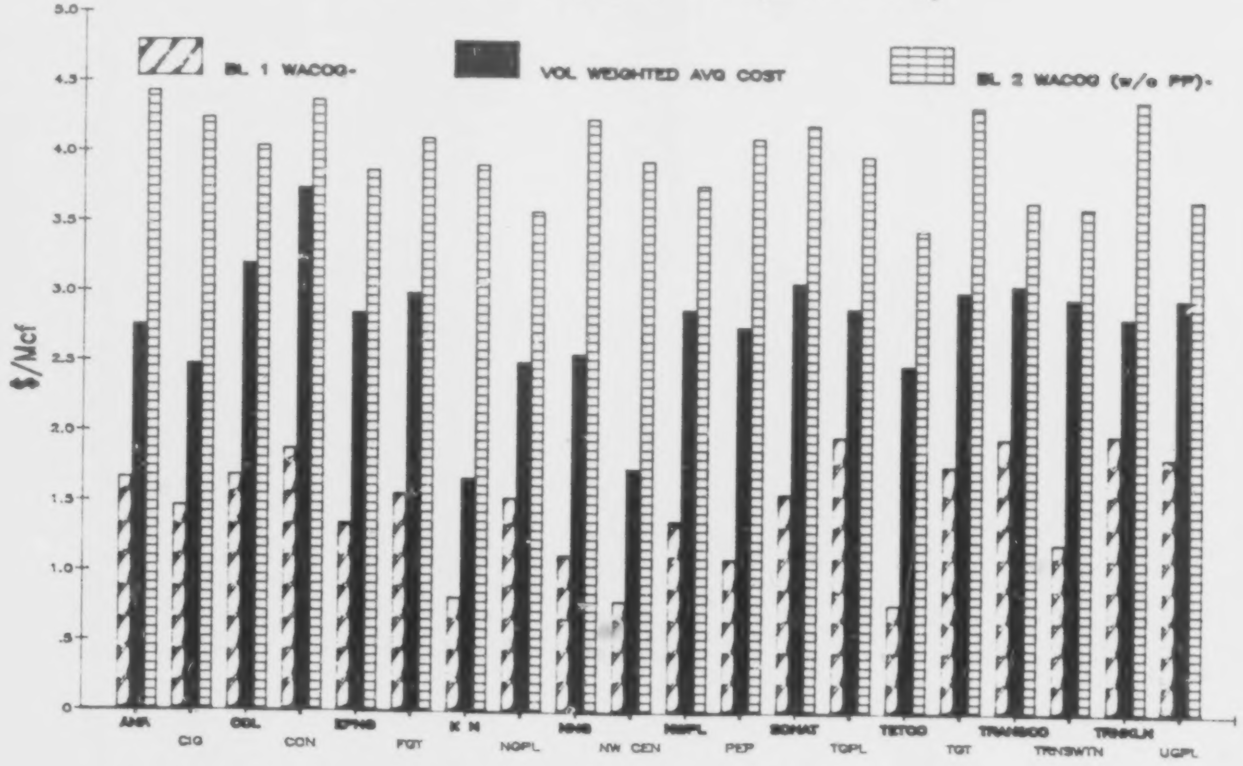
TESTIMONY OF
EDWARD J. SHEEHY
ON BEHALF OF
THE PETROCHEMICAL ENERGY GROUP

Committee on Energy and Natural Resources
Subcommittee on Energy Regulation and Conservation
United States Senate

July 11, 1985

Washington, D.C.

AVERAGE COST OF WELLHEAD PURCHASES
(Mid-1985 PGA Projections)



SOURCE: EIA

-As defined in RM85-1

PEG CHART 1

Page

QUESTIONS PRESENTED BY COMMISSION PROPOSAL.......... 1-5

If implemented as proposed, the results of the proposal can be worse than the status quo.

THE CUSHION PROBLEM IS NOT SOLVED BY CREATING A NEW FEDERAL ENTITLEMENTS PROGRAM.................. 5-9

The proposal to trifurcate the gas costs should not be adopted.

THE NONDISCRIMINATORY TRANSPORTATION POLICY MAY BE ILLUSORY...................................... 9-13

The transportation policy gives priority to local distribution companies over end-users.

THE TAKE-OR-PAY PROPOSAL IS UNLIKELY TO WORK......... 13-16

The complex and confusing formula proposed to remedy the take-or-pay problem is unrealistic and probably will be unappealing to both producers and pipelines.

WILL GAS SUPPLY BE ADVERSELY AFFECTED?.............. 16-17

We have not forgotten curtailments. We seek assurance that the proposed changes will not lead to a return to curtailments.

PENDING LEGISLATION................................ 17

Comment is reserved pending Commission action.

CONCLUSION... 18

We do not defend the status quo. There is a cushion problem, a take-or-pay problem, and a problem with obtaining nondiscriminatory transportation. The proposed solutions may be worse than the problems.

TESTIMONY OF EDWARD J. SHEEHY

My name is Edward J. Sheehy. I am Vice President, Productivity Management and Operating Services for Hercules Incorporated. Today I appear on behalf of PEG, the Petrochemical Energy Group. PEG is a group of independent petrochemical companies--those companies which are not vertically integrated with major refiners. 1/

Members of the Petrochemical Energy Group use gas for feedstock, process fuel, plant protection, other non-boiler uses and boiler fuel uses. Our members have manufacturing facilities in all parts of the United States. PEG members are participating or seeking to participate in the spot and longer term non-traditional gas markets.

1/ The U.S. petrochemical industry is vital to the economic welfare of the United States, and is a key contributor to the nation's trade balance. U.S. petrochemical industry sales in 1983 were nearly $80 billion. The industry employed 360,000 people, and invested $4 billion in new plant and equipment in the U.S. (*See* 1983 Petrochemical Industry Profile, prepared for the Petrochemical Energy Group, by Arthur D. Little, Inc., September 1, 1984.) The industry made a $7 billion positive contribution to the national balance of trade in 1983. (*See* Trade Trends in Petrochemicals: 1983, A Report to the Petrochemical Industry Group, Arthur D. Little, Inc., August, 1984.)

In responding to the inquiry, "the current state of and the factors affecting the natural gas market," we wish to concentrate on the pending action at the Federal Energy Regulatory Commission.

The Notice of Proposed Rulemaking in Docket RM85-1 2/ is an effort by a conscientious regulatory commission to cope with the cushion problem of the Natural Gas Policy Act of 1978 (NGPA), 3/ to restore transportation of natural gas in interstate commerce to vitality, and to solve the take or pay controversy. The effort, and the intentions behind the effort, merit commendation. The problems with the current situation have been correctly identified, but the proposed solutions to the problems may have consequences that will frustrate rather than accomplish the laudable objective of the Commission, even assuming that there is legal authority to do all that is proposed.

The Commission's stated goal in this rulemaking is

> to make such adjustments in our regulation of interstate transportation of natural gas as are required to ensure that the natural gas markets are viably and sufficiently competitive so that consumers are provided natural gas at

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2/ Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, Notice of Proposed Rulemaking, FERC Docket No. RM85-1-000 (Parts A-D), (Issued May 30, 1985). (References to the NOPR will be cited as "NOPR mimeo at __." References to regulations, unless otherwise stated, are to changes proposed in the NOPR to 18 C.F.R.)

3/ 15 U.S.C. §§ 3301-3432.

> the lowest reasonable rates consistent with reliable, long term service. 4/

While the Commission has chosen to issue a rule in four parts, functionally there are three parts which are currently complementary and which address: the cushion, nondiscriminatory transportation, and take-or-pay.

The cushion of cheap price controlled gas is to be taken away from the interstate pipelines. This is intended to render sales by pipelines vulnerable 5/ and induce the pipelines to volunteer to provide transportation service to the specification of the Commission and to allow their sales customers to terminate contracts. 6/ As an added inducement to volunteer, the pipelines are given the opportunity to buy their way out of take-or-pay problems, 7/ obtain licenses and operating flexibility more easily, 8/ including, in time, the opportunity to make an extra profit on the sale of gas. 9/ Pipelines regulated by the States must also transport, if they choose to benefit from the proposed

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4/ NOPR mimeo at 3.

5/ NOPR mimeo at 44, 51.

6/ NOPR mimeo at 27-28, 31-32, 83-85; see proposed § 157.21.

7/ NOPR mimeo at 9, 87-101; proposed 18 C.F.R. Part 161.

8/ NOPR mimeo at 9, 37-41, 102-114; proposed §§ 157.103 and 157.211.

9/ NOPR mimeo at 44-47, 121; proposed § 154.43(f).

rules. 10/ Local distribution companies are exempt from any comparable requirements.

If any one of the three parts has a flaw in its design, then the integrated program should not be implemented until the flaw has been corrected. If implemented as proposed, then the results can be worse than the status quo. Let us review some of the obvious questions:

1) Cushion. Is it likely that the problems caused by the cushion will be solved by the simple expedient of transferring the cushion from the control of companies regulated by the federal government to companies controlled by state governments and the creation of a new federal entitlements program?

2) Transportation. Is it likely that a non-discriminatory firm transportation system open to all shippers will result if priority is given to local distribution companies who, in turn, are not required to offer transportation service in exchange for the benefits of the program, as both inter and intrastate pipelines are?

3) Take-or-Pay. Is it likely that all producers will be willing to give to the pipelines the discretion to shut-in production for the remainder of the delivery obligation, just for a small fraction of projected payments?

10/ NOPR mimeo at 64-66; proposed §§ 284.122 and 284.123.

4) Gas supply. Is it likely that the prospects for a long term gas supply will improve or at least stay the same?

The answer to each of the above appears to be in doubt or in the negative. We will bring our concerns to the attention of the Commission in our comments with the hope and expectation that our fears will be allayed and that the necessary modifications will be made in the proposal.

THE CUSHION PROBLEM IS NOT SOLVED BY CREATING A NEW FEDERAL ENTITLEMENTS PROGRAM

Part D, the regulations dealing with the trifurcation of gas costs into three blocks, is theoretically the only mandatory regulation. 11/ It is the device selected to create an entitlements program 12/ which transfers the "cushion" of only the regulated categories of gas with a current ceiling price of $2.50 or less. 13/ This is block one.

In block two go all wellhead sales with a regulated ceiling price higher than that or a deregulated price, as well as synthetic gas and imports.

11/ NOPR mimeo at 22-23; proposed § 154.38(d)(4)(xi).

12/ NOPR mimeo at 47-48; proposed § 154.38(d)(4)(xi)(B).

13/ 18 C.F.R. Part 271, Subpart A, 50 Fed. Reg. 18242 (4/30/85).

The value of this entitlement to block one gas is a real plum. Using the latest available EIA data, 14/ it is possible to approximate the average price of wellhead purchases of gas on major pipeline systems and compare that to the block one and block two average prices, in accordance with the proposal. "Spreads" between the Block one and two prices of over $2.50 are not uncommon. (See Chart 1, p.i)

We have had considerable experience with federal entitlements programs, starting with the Mandatory Oil Import Program 15/ and continuing through the Emergency Petroleum Allocation Act and its progeny. 16/ All have been

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14/ We are again indebted to the Energy Information Administration for their excellent and timely compilation of data, current through the end of May, 1985. The database used in the attached Chart 1 is the EIA draft PGA9284, Table B-2 Projected Volumes and Prices of Wellhead Purchases for 1983-1984-1985, by major pipeline (May 30, 1985).

15/ The Mandatory Oil Import Program was established pursuant to § 232 of the Trade Expansion Act of 1962, 19 U.S.C. § 1862. The most recent implementing regulations are at 10 C.F.R. Part 213 (1982). The program is now inactive.

16/ Emergency Petroleum Allocation Act of 1973, Pub. L. 93-159, Nov. 27, 1973 as amended by
- Pub. L. 93-159, Nov. 27, 1973, 87 Stat. 627 (Title 15, §§ 751-756)
- Pub. L. 93-511, Dec. 5, 1974, 88 Stat. 1608 (Title 15, § 753)
- Pub. L. 94-99, § 2, Sept. 29, 1975, 89 Stat. 481 (Title 15, § 753)
- Pub. L. 94-133, § 1, Nov. 14, 1975, 89 Stat. 694 (Title 15, § 753)
- Pub. L. 94-163, title IV, §§ 401(a), (b)(1)-(3), 402(a), (c), 403(a), 451-462, Dec. 22, 1975, 89 Stat. 941-955 (Title 15, §§ 753-755, 757-760h)

[Footnote continued]

a disaster. 17/ Can we hope that this entitlements program will be any different? Will there be a "white market", where entitlements will be transferable for cash? 18/ Will there be an exception and adjustment procedure, where those

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[Footnote continued]
Pub. L. 94-385, title I, §§ 121, 122, Aug. 14, 1976, 90 Stat. 1132, 1133 (Title 15, § 757)
Pub. L. 96-294, title II, § 274, June 30, 1980, 94 Stat. 711 (Title 15, § 753).

17/ *See*, *e.g.*, Office of Energy Emergencies, DOE, *Preliminary Analysis of Federal Energy Emergency Preparedness Strategies: The EPAA Experience and Current Programs at the Department of Energy* (March 23, 1982); Data Resources, Inc., *The Economic Effects of Alternative Federal Responses to a Major Oil Shortfall*, A Report of the Technical Committee of the Petrochemical Energy Group (June 1981); *Report to the API, The Mandatory Petroleum Price and Allocation Regulations: A History and Analysis* (May 1981); U.S. Department of Transportation, *Federal, State and Local Responses to 1979 Fuel Shortages* (February 1981); Staff Report of the Bureau of Economics to the FTC, *Petroleum Product Price Regulations: Output, Efficiency, and Competitive Effects* (February 1981); *Senate Governmental Affairs Committee Report on DOE Gasoline Allocation Program*, Senate Report No. 97-__ (1981); *Report of the Department of Justice to the President Concerning the Gasoline Shortage of 1979*, (July 1, 1980); Cabot Consulting Group, *Evaluation of the DOE's Gasoline Allocations Program, Final Report, Contract No. DE-AC01-79-PE-70037* (June 6, 1980); GAO, *Gasoline Allocation: A Chaotic Program in Need of Overhaul* (April 23, 1980); DOE/EIA *An Analysis of Federal Government Energy Emergency Programs, Energy Policy Study Volume 5* (January 1980); DOE, *Report to the President on the Activities of Oil Companies Affecting Gasoline Supplies* (July 24, 1979).

18/ Cabinet Task Force on Oil Import Control, The Oil Import Question, February 1970, pp.15, 85.

who have little or no cushion may apply for subsidies or where competitors can seek equalization? 19/

And what assurance is there that the beneficiaries of the entitlements program share with their own customers? At least under the present system each and every consumer on any given pipeline system shared equally in whatever subsidy existed in the cushion. Now the cushion will be disproportionately allocated to some customers, mainly distribution companies, without any condition as to whether the benefits must be passed on to each and every consumer. 20/

We have been through the experience of the cushion once, and whatever progress the Commission has made in adjusting other features of federal regulation to mitigate the effect of the cushion on interstate pipeline purchasing practices will be forfeited as control over the cushion is lost. 21/ The power to regulate--or not to regulate--the price of gas in interstate commerce devolves upon the

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19/ Exception and adjustment procedures related to the crude oil entitlements program were provided for by § 7(b) of the Federal Energy Administration Act, 15 U.S.C. § 766(i)(1)(D) and § 504 of the Department of Energy Act, 42 U.S.C. § 7194. Regulatory provisions for the adjustments procedures are found at 10 C.F.R. § 205.20 *et seq*. and exceptions provisions at 10 C.F.R. § 205.50 *et seq*., 10 C.F.R. § 205.70 *et seq*. The NGPA provides for adjustments necessary to prevent special hardship, inequity, or an unfair distribution of burdens at § 502(c).

20/ NOPR mimeo at 47-48, 118-121; *see* proposed § 154.43(c).

21/ Letter of Chairman O'Connor to James T. Broyhill dated January 22, 1985 and his response to Question 23.

States, each of which may have some piece of the federal entitlements program to police.

Merely transferring the cushion from one class of gas companies to another class of gas companies does not eliminate nor solve the cushion problem. We will urge that the Commission not adopt Part D.

THE NON-DISCRIMINATORY TRANSPORTATION POLICY MAY BE ILLUSORY

We have long been advocates of a Commission policy to encourage the pipelines to provide transportation service. 22/ We expect to pay a just and reasonable rate for that service. We want the pipelines to profit from this business. We do ask that it be non-discriminatory, much as the Commission has proposed here. 23/ We understand the Commission to propose a new firm transportation service that is open to all potential shippers on a non-discriminatory basis, and that the class of shipper would include industrials as well as local distribution companies. Thus it

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22/ See, e.g., Statement of Leonard A. Cohn on behalf of the Petrochemical Energy Group regarding Interstate Transportation of Gas for Others, Docket No. RM85-1-000 (Phase I), presented to the Federal Energy Regulatory Commission on February 20, 1985; Statement of Edward J. Sheehy on behalf of the Petrochemical Energy Group regarding Deregulation and Other Pricing Changes on January 1, 1985, Under the Natural Gas Policy Act, Docket No. RM84-14, presented to the Federal Energy Regulatory Commission on October 11, 1984.

23/ See NOPR mimeo at 29-30; proposed sections 284.104, 284.124; but cf. regulations for blanket certificates for local distribution companies, proposed section 284.224, which omit nondiscrimination conditions.

is with regret that we must point out that this policy may well be illusory:

1) If there is insufficient capacity available on interstate pipelines to provide firm, year around transportation service. We have been unable to identify a Government study which would give us some comfort in the assumption that such capacity is available. We do, however, assume that there is considerable unused capacity available from time to time. 24/

2) If the Commission intends that year-round firm capacity will become available through the option given to distributors to terminate their contract demand with the pipelines over a four year period, 25/ we hesitate to accept this assumption, for two reasons:

(a) We have no reason to assume that all pipelines will be willing to tender a full release to all of their customers.

(b) We have no reason to assume that the distributors will rush to give up their contract demand rights. In a sense, the distributor can have the best of all possible worlds: with his entitlements given to him without strings of any kind as a subsidy, he may well be able to pay

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24/ Letter of Chairman O'Connor dated April 15, 1985 to James Broyhill and pages 38-39 of attachment thereto; Voluntary Carriage Through 1984, INGAA Issue Analysis, Policy Analysis Department, May 1985.

25/ NOPR mimeo at 31-32, 83-84; see proposed § 157.21.

whatever fixed costs are allocated to him in order to hold his capacity on the interstate pipeline and his right to draw gas from the pipeline, then not take gas from the pipeline so long as gas available through the new transportation program is cheaper. Please note that the new transportation service would be firm but that the distributor would not have to pay any charge for reserving the capacity. 26/ Thus the cost to the distributor of pursuing this strategy is favorable. If this fear of ours is realized, not only will there be little firm capacity available, but the pipeline becomes a standby storage service less able to serve industrial customers.

3) If our fears expressed above prove groundless, and firm capacity year round is available, even by means of termination of contracts by distributors, we then face the threat that the Commission will give preference to local distribution companies in assigning firm capacity. 27/

26/ NOPR mimeo at 24, 33-35, 55-63; see proposed § 284.7(b)(2).

27/ Note that proposed section 157.21 of the new regulations would allow firm sales customers of interstate pipelines to reduce contract demand under their firm sales service agreements with a pipeline if that pipeline has accepted a certificate authorizing certain kinds of transportation for others or has transported gas for others under authorities granted by § 311 of the NGPA. The explanation of the policy envisioned under the regulations at mimeo 31-32 suggests that the Commission is considering allowing firm sales customers to convert their rights to purchase gas from pipelines to a right to have gas
[Footnote continued]

4) Even if we can somehow get access to the firm capacity on the interstate systems, we are still beaten if we cannot get gas to our plants because the local distribution company either refuses to transport or charges a prohibitive rate. The Commission proposes to impose a non-discriminatory transportation condition on intrastate pipelines which take advantage of the federal programs, 28/ but no such condition is imposed on distributors who accept entitlements and the benefits of the new transportation policy, not even when the regulations involve distributor transportation. The Commission should condition availability of any benefits to those who implement a nondiscriminatory transportation policy on their own system. 29/

5) Finally, if our plants happen to be close enough to an interstate pipeline to make a direct connection feasible, we do hope that nothing will impede the

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[Footnote continued]
transported by those pipelines.

Distributors would apparently not be entitled to convert purchase entitlements to transportation entitlements where the pipeline declined to perform transportation service under § 311 or to seek transportation certificates provided for in proposed sections 284.221 or 157.105.

28/ NOPR mimeo at 64-65; proposed § 284.122.

29/ *See* note 23, *supra*.

Commission's intent to allow the new optional certificates to provide access. 30/

In our view, the entitlements program is, in actuality, a barrier to the policy of providing non-discriminatory transportation service to all shippers. If only one class of potential shipper has the benefit of the subsidy, that class can not only out-bid the other class for gas at the wellhead, but can also use the cushion to tie up capacity for transportation. This is another reason why Part D should not be adopted.

If industrials are to be allowed non-discriminatory access to the transportation of natural gas, then these concerns must be addressed.

THE TAKE OR PAY PROPOSAL IS UNLIKELY TO WORK

We will, of course, defer to our colleagues in the producing and the interstate pipeline sectors on this issue. If they say that it is attractive, we will accept that statement. For present purposes, we look at the proposal from a business perspective and reach the conclusion that a prudent businessman is unlikely to allow his purchaser to tie up all of his capacity for a term certain without any obligation to pay anything at all except for a one time payment of a small fraction of the minimum payment requirement.

30/ Proposed § 157 Subpart E.

As we understand the calculation of the lump sum, which is only presumptively available to achieve the result, the pipeline first sorts its contracts into two sets, one labelled "problem." 31/ These presumably are those with contractual provisions which require the pipeline to purchase a certain number of units or to maintain the cash flow at a certain level agreed to by both parties to the contract.

Step two is to sort the set of "problem" contracts into two sub-sets, one called "qualifying", the other apparently non-qualifying. 32/

Step three is to divide the subset of "qualifying" contracts into two further subsets, one longer term, one shorter term. 33/

Step four is for the pipeline to determine the time remaining in each qualifying contract's primary term after January 1, 1986 and then to calculate the liability it anticipates under the contracts in both sub-sub-sets for failure to honor the cash flow clauses under the contracts. 34/

31/ NOPR mimeo at 87; see proposed § 161.2(c).

32/ Proposed § 161.2(a).

33/ Proposed § 161.2(d).

34/ Proposed § 161.2(b).

Step five is then to determine the take-or-pay obligation for each qualifying contract for a two year period beginning January 1, 1986. 35/

Step six is to calculate the "unrecoupable" amounts, apparently that part of the cash flow payment which the pipeline will not be able to recover through subsequent takes of gas. 36/

Step seven is then to suggest a fraction of step six for each of the two subsets which will yield a gross sum of money which may be used to settle future take or pay claims. 37/

Thus, leaving aside steps one to three, in step four there is the first fraction of the potential liability, in step six there is a fraction of that fraction, and in step seven there is another fraction of the preceding two fractions.

Looking at the situation from the pipeline's standpoint, if it does all of this with success, its efforts are still open to challenge 38/ and it recovers the lump sum

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35/ Proposed § 161.2(c)(1).

36/ Proposed § 161.2(c).

37/ Proposed § 161.2(d).

38/ Proposed §§ 161.3(a) and (b) and 2.76.

payment over a five-year period without any carrying charge. 39/

Thus, while we hope that an equitable solution can be found to mitigate or eliminate the problems presented by the take-or-pay issue, we doubt that this one will work.

WILL GAS SUPPLY BE ADVERSELY AFFECTED?

We have not forgotten the curtailments of the 70's. In times when there seems to be enough deliverability of gas for everyone, if only the transportation systems could be opened on a non-discriminatory basis, it is perhaps less than fashionable to ask whether there is any risk that the Commission's integrated proposal will have an adverse impact on long term gas supply.

We cannot help but notice a certain series of commentary by the Commission. It is recognized that the "second block would be priced higher than a pipeline's present WACOG, which includes old gas. However, since customers would be purchasing from both blocks, a given pipeline customer's total gas costs might not necessarily change." 40/

Subsequently, the Commission states "[a]s competition increases between pipelines, or on a pipeline system between sales and transportation, this three-part rate

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39/ Proposed § 161.4(a)(3) and (4).

40/ NOPR mimeo at 44.

structure should serve to lower gas prices in the second block and act as a disincentive to imprudent pipeline gas purchasing practices." 41/

It thus appears that the Commission's proposed regulation of gas at the pipeline level will affect the price at the wellhead of both regulated and deregulated gas.

This effect is not a result of the free market, but rather is the result of a change in federal regulation.

In the past, federal regulation affecting the price of gas at the wellhead has led to curtailments.

Therefore, we feel justified to ask the Commission whether long term gas supply will be adversely affected by this change in federal regulation. As we noted at the outset, the Commission recognizes that its goal is to provide consumers with gas at the lowest reasonable rates "consistent with reliable, long term service." Supra note 4.

PENDING LEGISLATION

We are aware of the bills pending on the subject of natural gas. 42/ Unless otherwise directed, we would prefer to defer comment on those bills until some resolution of what the Commission will do occurs.

41/ NOPR mimeo at 51.

42/ See S. 1302, S. 1251, S. 834 and H.R. 2734, H.R. 2185, H.R. 511, H.R. 316, H.R. 294.

CONCLUSION

We will bring these concerns to the attention of the Commission. We will urge deletions and modifications in the proposal. We do so, not in defense of the status quo, but rather acknowledging the identification of problems by the Commission: the cushion problem, the take or pay problem, and the problem of non-discriminatory transportation. We want the situation to improve; we do not want the "solution" to a problem to be worse than the problem itself. The problems facing the gas industry today may transcend the ability of the Commission to deal with them, and it may be necessary for the Congress to address legislation.

Thank you for this opportunity to be heard.

Senator NICKLES. Thank you.

Mr. Gooch, did you have any opening comments?

Mr. GOOCH. No, thank you, Senator.

Senator NICKLES. I'm glad that the first panel is all in agreement on natural gas and the proposed rulemaking. Some of you say that we have a shortage that is imminent, and some say we have plenty, and some say that carriage would be the salvation, some say the downfall. Did anybody say we should forever regulate old gas?

[No response.]

Senator NICKLES. That is quite a change.

Mr. Terpstra, you mentioned in your comments that you felt that total deregulation would be preferable to the proposed rulemaking?

Mr. TERPSTRA. Yes. Then at least we'd have something.

Senator NICKLES. Is that just with your pipeline?

Mr. TERPSTRA. I can only speak for our pipeline. We have just looked at it, and what it does is give us a lot of negatives. But it takes the balancing.

When we looked at NGPA, we felt that the balance inherent in that program was that the so-called cushion of the old gas prices would perhaps be offset by drilling incentives. And if old gas is deregulated, there has to be some mechanism to help pull down the NGPA prices that are above market. That's our concern all the way through, that if something is done for the old gas, if it's either given away, so to speak, as proposed by the FERC at the present time, or if it's deregulated, there has to be a counter incentive to induce certain producers who may not be the same parties that hold the 104 gas to negotiate down their NGPA contacts close to the market.

Senator NICKLES. I think many times when we hear the term deregulation of old gas, that raises a lot of flags and it means different things to different people. To some people it means that all those contracts would be abrogated. I, for one, have reservations about that. And so, in our bill, we didn't propose abrogating contracts, but we basically stated that those contracts would be deregulated as they expired or as they were renegotiated.

Do you have a problem with that or would you think that would be a proper approach?

Mr. TERPSTRA. Well, we think that could raise the cost to consumers somewhat because what would happen is as the old gas deregulates, that would be brought up to market levels, but there isn't a mechanism to encourage an offset on the NGPA gas. That's our concern. It would probably be more moderate than if it were done at one time, with no incentive on NGPA.

So it's a compromise.

Senator NICKLES. If you, as a gas company, were renegotiating, say, a 104 contract—I'm assuming that you buy a substantial amount of gas, say, from the Hugheton Field, which would still be under the category 104, perpetually regulated gas—if you're renegotiating that contract, and let's say the price of it right now is 70 cents, if it were renegotiated, would you automatically find that at a market price, or would you be renegotiating it somewhere between that price, depending on the leverage you had with the producers, or what?

Mr. TERPSTRA. I think it would depend on the leverage with that particular producer. Like I said, I believe some of the problem is that the holder of that gas may not be a significant supplier of your NGPA gas or something like that. That's the difficulty you get into.

Mr. MCGRATH. Mr. Chairman, if I could respond to your question on the forever regulated gas, our position has been, up to now, at least, that we do not favor any change in the NGPA as of today.

We have looked at your bill, S. 1302, and we are looking at it, and right now I'm not in a position to say how we'd come down on it. We hope to have an answer fairly soon. But the NOPR, as I indicated in my statement, has sort of turned things, for us, at least, a little topsy-turvy in terms of focusing on where its impact would be. So we don't have at this moment any change in our position with respect to forever regulated gas. But we are looking at your bill.

Senator NICKLES. I appreciate that.

It's interesting. I postponed this segment of the hearing to give more time for analysis of the NOPR because, realizing that it was difficult and confusing in several different perspectives, that you have to look at each piece and then may be try and put the pieces together and see if, on the whole, it would be, one, advantageous for the country, for the industry, for maybe whatever group that you happen to represent. It may be that we needed to give it a couple of more weeks.

We could have had this thing 2 months from now, and you may still be coming back with we need more time to look at it.

[General laughter.]

Senator NICKLES. I understand that.

We talked about the health of the industry with Mr. McGrath and Mr. Lawrence particularly, and maybe Mr. Terpstra as well. We heard a lot when we were in the natural gas debates a couple of years ago about several of the pipelines. We heard a lot from your industry, I guess, about several of the pipelines being in severe financial or bad shape. Some we were hearing were looking at, you know, if contracts weren't renegotiated. Mr. McGrath, in your statement, you mentioned that a lot of contracts were being renegotiated. I don't know. Do you have any idea of, one, what the health of the pipeline industry is overall, and, two, have a substantial majority of the contracts been renegotiated?

Mr. MCGRATH. Well, over all, the health of the industsry is good, Mr. Chairman. As I indicated in my statement, we have, for the last 2½ years, been in, if you will, a state or turbulence because of the marketing situation in which we have come on to, and the decline in demand, the drop in oil prices, the high take or pays that the companies have been confronted with, the surplus in deliverability, a convergence of factors, which has made it very difficult for the interstate pipelines.

Their health is not as good as we'd like to have it be, but we're not failing, let's put it that way.

Senator NICKLES. Did you mention in your statement that there was a substantial increase in volume of gas that was moving, say, 1984 compared to 1982?

Mr. McGRATH. Oh yes—on transportation. Yes, transportation has been increasing significantly, and the important part is that it's increasing for distributors and end users, as compared to the normal or historical transportation, which was between pipelines, one for another, let's say.

The big increase has been for distribution and for end users, and there's a great increase in that.

Senator NICKLES. Total volumes of gas moving, not just between interpipelines?

Mr. McGRATH. No, the volumes of gas moving have been increasing as well as the number of transactions.

I have in my full statement a reference to the amounts.

Senator NICKLES. Mr. Lawrence.

Mr. LAWRENCE. I think, as to the health of interstate pipelines and producers, probably the single most important problem is the take-or-pay obligation. It's significant. The way the Commission has addressed it in the NOPR is one that says: "Pipelines, if you will buy out your take-or-pay obligation, we'll presume that that's just and reasonable and include it in your cost of service." But it doesn't make the gas marketable.

The solution, as I mentioned earlier, to the take-or-pay problem, is to improve this demand. And that's something this committee and this Congress can address, and that is remove the market restraints on natural gas.

Senator NICKLES. I appreciate that.

Mr. Terpstra, to complete the line, I mentioned in my particular proposal, as pertained to old gas, that we didn't go in and abrogate those contracts. Likewise, if you were here 2 years ago, I was one saying that we shouldn't by Government mandate abrogate the high cost.

I personally have a real problem for the Federal Government going in and abrogating all the contracts that are out there, whether they be higher than market or whether they be lower than market.

I heard several different comments. Mr. McGrath, yours probably is negative on NOPR and Mr. Terpstra's comments are negative on NOPR.

Mr. TERPSTRA. Well, I would say that the end goal of a more market-responsive industry we support. We have trouble with issues like the blocking and some of that.

Senator NICKLES. We want to separate the blocking from the rest of NOPR right now. I heard complaints on the blocking from every individual on the panel. Correct me if I'm wrong.

Mr. McGRATH. That's correct.

Mr. BUSH. Right.

Mr. McGRATH. Let me echo what Mr. Terpstra has said and make our position clear.

We think the Commission has made a very bold effort here to try to address the critical problems that the whole industry faces—Mr. Elam's company, Mr. Bush's producers, the pipelines, Mr. Lawrence's distributors—to address the market situation which all of us are facing, and the problem of getting gas to the consumers at a reasonable price and sound pipeline operations and so forth.

The Commission has made a bold move there. It's a very radical change in the way the industry is going to do business if this proposal is adopted.

We think that there are—and we want to work with the commission to make it workable. The problem is, as we've pointed out, that there are aspects to the proposal, critical aspects, not just the billing procedure, but others, the take-or-pay buyout, for example, and others, of transportation, and the access, that need to be modified in significant ways.

We are recommending to the Commission, in our comments to be submitted next week, changes to be made in the proposal that we think would make it more usable, would make it more workable, for all concerned.

But if my statement here this morning seemed negative, it was intended to call to the attention of the subcommittee the problem areas that we see in the proposal. And we are anxious to work with the Commission to straighten them out if we can.

Senator NICKLES. Mr. Bush.

Mr. BUSH. Mr. Chairman, I didn't want to infer that we hadn't reached some judgments already on the NOPR. We have. As I mentioned, the block billing is certainly one of the ones that we have considerable concern wtih. And you really can't separate block billing. You can't separate any part of this. It's an integrated rulemaking, and it all fits in together.

The fact is the way the block billing is set up is extremely bothersome from a number of points.

One is it seems unlawful. It seems to be in violation of section 4(b) of the Natural Gas Act. It may or may not be. I don't know. I think that's one question that's been raised about it. The reason being that it certainly sets up a highly discriminatory practice with regard to which customers are going to enjoy the advantages of forever-regulated gas.

What's more, we conclude that it takes a significant amount of economic rents that would originally have remained within the producing industry, supposedly under, as Mr. Lawrence and others at the panel have said, that were supposedly not meant by the Congress, as it's been interpreted by the Commission, to be passed on to some select group of customers, but to provide supply for all customers. That was the basis of incentive pricing, I thought.

You know, the NGPA was supposedly setting up schedules by which it was going to provide incentives. I enjoy the fact that the NGPA was written at a time when the former DOE had concluded that we had a finite resource base and we were about to fall off the cliff.

We listened to Mr. O'Leary at length preach about the fact that gas was gone, oil was gone, domestically, and that the NGPA was an effort to not only manage supply, but manage demand. The whole National Energy Act was set up that way.

And now we have this revisiting of that whole conversation as if it never existed.

The fact is that there is a big difference between potential supply and an economically sensible way of retrieving that.

When you set off block billing the way that they do in the Commission, it is moving capital, and it is taking economic rents from the producing industry as it was supposed to supply future supplies, and moving it away. It's going to move it somewhere downstream.

Now, we hear a lot about producing decisions made on market-sensitive prices. Pricing is only one decision upon which a producer makes a drilling decision, as I'm sure you're aware. And one of the big things is how much capital.

He may have 10 prospects that are very good to be drilled at $2.75. But he may not have the capital to drill all but four.

Now, the question is do you want to take capital out of an industry that's already suffering tremendous setbacks in terms of revenues realized to it, and an industry that is the underpinning of the economic growth of all the companies downstream of us, and do you want to take out those revenues and move them somewhere downstream, to be captured by God knows who, and take them away from the supply aspects of this business? We will contend, obviously, that you shouldn't do that and that it makes no economic sense as well as energy sense.

So, we're going to comment very vigorously on that.

We also will object, as well, to the take-or-pay aspects for different reasons.

Senator NICKLES. Senator Hecht, did you have a question?

Senator HECHT. First of all, Mr. Chairman, I want to compliment you on holding these hearings. I like to see people from industry come to Washington and tell us how their industry is. It's always the other way, where we in Washington tell them, and that's the wrong way to do things.

In the interest of time, I am going to forgo my time because I want to hear the next panel, and I have another committee hearing to go to, but I may submit some questions at the end.

Senator NICKLES. I appreciate that.

Senator Rockefeller.

Senator ROCKEFELLER. I will yield to similar pressure.

Senator NICKLES. Thank you.

Before our panel leaves, I have just a quick question.

Again, most everybody mentioned some problems with the block pricing, and I think part of the block pricing assumptions that FERC was making was that we would have forever-regulated gas.

Couldn't we eliminate a lot of that if we did deregulate old gas, whether it be on the schedule that I've proposed? Mr. Elam, you said within 2 years, which I am assuming you would have to have contract abrogation in that to deregulate everything in 2 years.

Mr. ELAM. Yes, sir. We said that 2 years ago, though.

Senator NICKLES. I understand. [General laughter.]

We didn't pass that bill, either. [General laughter.]

I'd like to get something we could pass.

Again, I have a problem with contract abrogation. I think a lot of people do. A lot of people, regardless of whether it's old gas, new gas, who benefits, who doesn't benefit, and so on, getting out of all those questions, I think a lot of people have problems with massive contract abrogation.

But, again, I look at this block pricing scheme as basically a real inequity that's going to lock in those inequities.

Some of your companies, Mr. Elam, may be fortunate enough to be one of those that's going to be locked in on that low-priced gas.

Mr. Terpstra, some of the people that you supply would be. I'm sure of that. But also you may have somebody 30 miles away that is not in that block, and they may be competitors, and one is going to have a very low priced gas compared to a very high priced gas, and I see that as a real inequity as well.

Mr. TERPSTRA. That's correct.

Mr. ELAM. Mr. Chairman, our experience has been that, even if our local distribution companies benefit, we don't always get a passthrough on that benefit.

Senator NICKLES. I understand that.

Mr. ELAM. We would remain skeptical.

Mr. LAWRENCE. Senator, could I comment?

I think the treatment of 104 gas in the NOPR are pluses and minuses as far as the political aspects of deregulating old gas.

I think you've heard some very good arguments today in favor of the fact that, yes, the answer to your question is yes. I think all of these gentlemen are saying, in essence, that your form of deregulation would alleviate some of the problems seen in that NOPR.

I personally think that is true.

And, again, I mean this. I'd like to compliment you on the approach you have taken to the old gas deregulation issue, as tough as it is. And I would also note that that's been picked up in the legislation on the House side by both Republican and Democratic sponsored legislation.

They have used the expiring contract and renegotiated contract as the route to deregulating old gas—far different from what this committee and this Senate voted on a year and a half ago.

As tough as that issue is, in my opinion, you're on the best track to address it.

But, again, I appeal to you, if the political winds are such that it isn't going to happen on the old gas, there are some awesome persuasive reasons for getting rid of the market restraints, a rifle shot approach.

Senator NICKLES. I understand that.

As you, I am sure, are aware, I also in previous times have introduced legislation that dealt strictly with the Fuel Use Act, and/or incremental pricing, as well.

Mr. Elam.

Mr. ELAM. Mr. Chairman, in the comments that we will file with FERC, we have a solution to that part, the problem. I won't go into it now, because not all of our members have signed off on it, but we will file this with your subcommittee.

Senator NICKLES. I would appreciate it.

I think most of you mentioned that you would be filing comments with FERC in the near future. We're not looking for your 300 page cases, but if you could give us the synopsis of your opinions on those, we would appreciate it.

Mr. MCGRATH. We will do that.

Senator NICKLES. Thank you very much.

In our next panel, we have Ray Potts, vice chairman of the Natural Gas Committee of the Independent Petroleum Association of America; Stanley Balis, general counsel of the American Public Gas Association; James Atwood, vice president of Nitrogen Manufacturing, from Farmland Industries; and Mark Cooper, energy director, Consumer Federation of America.

Mr. Potts, we welcome you as former president of the Oklahoma Independent Producers, and also as vice chairman of the Natural Gas Committee for the Independent Petroleum Association of America.

STATEMENT OF RAY H. POTTS, VICE CHAIRMAN, NATURAL GAS COMMITTEE, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

Mr. Potts. Thank you, Mr. Chairman.

I am speaking on behalf of the nearly 15,000 independent oil and gas producers, as well as 35 unaffiliated State and regional associations.

Again, at the outset, we would like to, as the previous panel indicated, have the record kept open in order that we may file some final comments regarding RM 85-1. These will be filed on Monday, July 15.

We especially want to commend you for your tireless efforts in trying to find a solution to this natural gas problem. Probably nobody, with all due respect to your colleagues, has worked harder to try to find a solution to a very important problem to this Nation.

Probably no industry in America has been impacted more politically and motivated economically in the tinkering that has taken place in the 30 years as has ours. From the *Phillips* court decision in 1954, to major Federal Power Commission interpretations of that decision in 1960, to the passage of the NGPA in 1978 have producers seen their economic fortunes tied more to the political decisions than to sound supply-demand conditions.

We cannot look at today's problem, however, without recognizing certain mindsets that have developed over the past years of rigid regulations. Because of long years of low wellhead price controls, the market for natural gas in the interstate grew on one basis—low prices.

In the mid 1970's, the total annual production was something like 22 trillion. I think this year we are looking at something like 17 trillion, a significant drop.

About the same time that the low prices stimulated demand, it also worked to discourage drilling and the finding of new reserves. Finally, as we all remember, this led to the curtailment in the late 1970's.

Because higher uncontrolled prices worked so well to increase supplies in the intrastate market of the Southwest, Congress took action to help the interstate systems in 1978, when they passed the NGPA.

NGPA was designed to increase supplies to interstate market, high priority users in three basic ways. First, it opened up the previously closed interstate market to uncontrolled supplies in the intrastate market. This brought an immediate end to curtailment.

Second, it moved to dampen high volume demands by limiting and prohibiting construction of major new industrial and utility facilities burning gas as a fuel. Finally, using the volumes of old, low-priced gas remaining under wellhead controls, it proposed to pay producers incentive prices to increase production.

All of these actions seemed logical in many ways. However, all had a common flaw: they denied the existence of basic laws of supply and demand and the impacts on markets of alternate fuel sources and the market prices of these sources.

The fact that market prices of these alternative fuels began a steady decline after 1981 while NGPA acted to steadily increase the average gas price only exaggerated the problem.

Thus, as we approached January 1, 1985, the drop-dead date for most of NGPA pricing features, we found wellhead prices varying from as low as 28 cents to as high as $10 per mcf. But, more importantly, we had seen average wellhead prices of gas increase by 30 percent between 1981 and 1984, while alternate, liquid fuel prices had a drop of 20 percent.

If that disparity was not enough to make gas less competitive, transporters took this occasion to more than double their average sale prices. While average producer prices increased by 65 cents per mcp between 1981 and 1985, prices to the industrial users went up to $1.12; to electric utilities it increased by 80 cents; and to residential users the increase was $1.77.

The challenge to all of us today—producers, pipelines, utilities, users, regulators, and legislatures—is to get on with the task of balancing supply and demand of gas at price levels that are competitive at the burner tip, yet adequate enough at the wellhead to bring on sufficient supplies.

That's not easy, as you know.

I would like to restate, because of a recent midyear meeting of IPAA what our gas policies are:

Continue to battle against moves in Congress to increase the tax burden on the natural gas producers;

Resist actions by FERC and Congress designed to arbitrarily reduce producers' prices and alter two party contracts, directly or indirectly;

Seek FERC action and legislation to increase market competition through contract carriage and any other actions designed to make it easier for buyers and sellers of gas to reach mutually advantageous agreements;

Seek legislation to grant producers limited antitrust exemptions so that they might form cooperative marketing entities;

Seek legislation to repeal the Fuel Use Act and incremental pricing in conjunction with legislation to give producers greater access to new markets;

Seek legislation to end all wellhead controls for natural gas when contracts expire or are renegotiated;

And continue to develop and expand programs to inform State utility commissioners and consumers of the elements of public policy necessary to assure adequate future supplies of natural gas at affordable prices.

Sir, we commend you, Senator Bradley, Senator Johnston, Senator Domenici, and others for having introduced legislation designed to address one or more aspects of Federal law still distorting the free flow of natural gas from wellhead to burner tip to all customers at rational prices.

Likewise, we commend the FERC for its bold action in issuing its current rulemaking. And while producers have some problems with specifics of this proposed rulemaking, we hope that we can work within the framework to bring about constructive changes.

In conclusion, we hope this committee continues to prepare itself to take needed legislative action.

The FERC is limited in some areas by the existing legislative authority. And because of that fact, its actions may result in some unintended distortions and shortfalls, and we hope that you will be ready and willing to move to fill these legal gaps.

In the meantime, we remain available to counsel with you both formally and informally. A healthy, expanding natural gas industry is too important to the basic economic foundation of our economy to receive less than our fullest attention and our best results.

Now, if I could just comment quickly on behalf of the Oklahoma Independent Petroleum Association, I have some comments related to Oklahoma that I would like to have you hear.

Oklahoma's natural gas industry has not been immune from the ravages of the current glut of natural gas supply and deliverability. To the contrary. As you know, the State of Oklahoma has been, in many ways, the first to suffer.

It's true that producers sold more gas in 1984 than in any previous year. However, the average price paid for the gas was down 5 percent, and represents the third lowest price paid—lowest price paid—in the 1980's.

So far, in 1985, indications are that the average price paid will be even lower.

As you know, Senators, the entire State is suffering from a downtown in the natural gas industry. Revenue from service tax is lower, revenue from personal and corporate income tax is lower, and unemployment is higher.

Several matters currently pending have the potential to make the situation much worse.

While OIPA does not completely agree with FERC's proposal as to RM 85-1, we commend them for having the courage to propose major changes, especially in the area of transportation of gas.

Currently, the natural gas industry is in a hybrid state. We're half free and we're half regulated. After 6 months of this unique condition, OIPA feels it's safe to say predictions and projections of skyrocketing natural gas prices have proven immensely wrong.

Without question, OIPA's main concern is for the independent producer, because it is the independent of this country who drills 90 percent of all the wildcats and who reinvests over 108 percent of our cash flow each year in additional drilling.

From OIPA the byword is caution and careful consideration of all changes affecting our industry during this very volatile period. Our ultimate objective is to move all segments of the natural gas industry from a regulated market to a market that is totally controlled by the laws of the free marketplace.

In conclusion, let me say that in my 31 years that I've been in the oil and gas business, I have never seen the natural gas market and industry in such a volatile situation. It is absolutely chaos. The previous panel mentioned about spot prices being $2.75, in that range.

In Oklahoma, the spot prices are about $2.30 on an average. Recently, a major producer selling some 15 to 20 million per day netted back $1.95 at the wellhead.

It is frightening, sir.

Thank you.

[The prepared statement of Mr. Potts follows:]

STATEMENT OF

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

AND

AMERICAN ASSOCIATION OF PETROLEUM LANDMEN
ARKANSAS ROYALTY MEMBERSHIP
CALIFORNIA INDEPENDENT PRODUCERS ASSOCIATION
COASTAL OIL AND GAS ASSOCIATION
EASTERN KANSAS OIL AND GAS ASSOCIATION, INC.
EAST TEXAS PRODUCERS AND ROYALTY OWNERS ASSOCIATION
ENERGY CONSUMERS AND PRODUCERS ASSOCIATION
GEORGIA OIL AND GAS ASSOCIATION
ILLINOIS OIL AND GAS ASSOCIATION
INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
INDEPENDENT OIL PRODUCERS TRI-STATE, INC.
INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO
INDIANA OIL AND GAS ASSOCIATION
INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS
KANSAS INDEPENDENT OIL AND GAS ASSOCIATION
KENTUCKY OIL AND GAS ASSOCIATION
LIAISON COMMITTEE OF COOPERATING OIL AND GAS ASSOCIATIONS
LOUISIANA LANDOWNERS ASSOCIATION INC.
LOUISIANA ASSOCIATION OF INDEPENDENT PRODUCERS AND ROYALTY OWNERS
MICHIGAN OIL AND GAS ASSOCIATION
NATIONAL STRIPPER WELL ASSOCIATION
NEW YORK STATE OIL PRODUCERS ASSOCIATION
NORTH TEXAS OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
OKLAHOMA INDEPENDENT PETROLEUM ASSOCIATION
ORANGE COUNTY PETROLEUM ASSOCIATION
PANHANDLE PRODUCERS AND ROYALTY OWNERS ASSOCIATION
PENNSYLVANIA GRADE CRUDE OIL ASSOCIATION
PENNSYLVANIA OIL AND GAS ASSOCIATION
PERMIAN BASIN PETROLEUM ASSOCIATION
ROYALTY OWNERS AND INDEPENDENT OIL AND GAS PRODUCERS ASSOCIATION OF ARKANSAS
TENNESSEE OIL AND GAS ASSOCIATION
TEXAS INDEPENDENT PRODUCERS AND ROYALTY OWNERS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
WEST CENTRAL TEXAS OIL AND GAS ASSOCIATION

BY

RAY H. POTTS

BEFORE THE

SUBCOMMITTEE ON ENERGY REGULATION
COMMITTEE ON ENERGY AND NATURAL RESOURCES

UNITED STATES SENATE

JULY 11, 1985

I am Ray H. Potts, an independent oil and gas producer from Oklahoma City. I am appearing here today as vice chairman of the Natural Gas Committee of the Independent Petroleum Association of America. Together with the more than 35 unaffiliated state and regional associations which join us in these comments, I am speaking on behalf of nearly all of the 15,000 independent oil and natural gas producers operating in all of the domestic oil and gas provinces of the U.S., particularly onshore in the lower 48 states.

At the outset, we would hope that the record of this hearing will be kept open for several days. We currently are working on our final comments to the Federal Energy Regulatory Commission on its Notice of Proposed Rulemaking (RM 85-1-000). We will be filing those comments on Monday, July 15, and we hope that we might submit them to this Committee as an official part of your hearing record.

We appreciate the opportunity you have extended to us today to address the current state of the natural gas industry, and I want to especially commend you, Mr. Chairman, for your tireless efforts to find a solution to our natural gas problems. You and I know there is widespread disagreement on what should be done and I want to thank you for your courage and persistance in trying to find an answer.

Probably no industry in America has been impacted by more politically motivated economic tinkering over the past 30 years as has ours. From the Phillips Supreme Court decision in 1954, to major Federal Power Commission interpretations of that decision in the 1960's to the passage of the Natural Gas Policy Act in 1978, natural gas producers have seen their economic fortunes tied more to political decisions than to sound supply demand conditions.

While that bit of history is behind us now and we find ourselves with more than half of all natural gas decontrolled as to price at the wellhead, we cannot look at today's problems without recognizing certain mind-sets which developed over those past years of rigid regulations.

Because of long years of low wellhead price controls, the market for natural gas in the interstate market grew on one basis -- low prices. By the mid 1970's total annual production based on those price induced markets reached 22 Tcf per year.

However, about that same time, the same low prices which stimulated demand so well, worked to discourage drilling and reserves and supplies available to the interstate market began to decline. This led to the need to curtail deliveries to low priority users and to find ways to try to stimulate production.

Because higher uncontrolled prices had worked well to increase supplies for the intrastate markets of the Southwest, Congress took action to try to help the interstate markets by passing the Natural Gas Policy Act of 1978.

It was designed to increase supplies to interstate market high priority users in three basic ways. First, it opened up the previously closed interstate markets to uncontrolled supplies in the intrastate market. This brought an immediate end to curtailments. Secondly, it moved to dampen high volume demand by limiting and prohibiting the construction of major new industrial and utility facilities burning gas as a fuel. And finally, using the volumes of old, low priced gas remaining under wellhead controls, it proposed to pay producers incentive prices to increase production.

All of these actions seemed logical to many, however, all had a common flaw -- they denied the existance of basic laws of supply and demand and the impact on markets of alternate fuel sources and the market pricing of those sources. The fact that market prices for those alternative fuels began a steady decline after 1981 while NGPA acted to steadily increase average gas prices, only exaggerated the problem.

Thus, as we approached January 1, 1985, the "drop dead" date for much of NGPA's pricing features, we found wellhead prices of natural gas ranging from 28 cents on the low end to nearly $10 on the high end. But more importantly, we had seen average wellhead prices of gas increase by 30 percent between 1981 and 1984 while alternate liquid fuel prices had dropped by 20 percent.

If that disparity was not enough to make gas less competitive, transporters took this occasion to more than double their average sales prices. While average producer prices increased by 65 cents per mcf between 1981 and 1985, prices to industrial users went up by $1.12 mcf, to electric utilities by 80 cents and to residential users the increase was $1.77.

It then is not surprising to see demand for gas dropping, resulting in a surplus or "bubble" at the wellhead.

The challenge to all of us today, producers, pipelines, utilities, users, regulators, and legislators, is to get on with the task of balancing supply and demand of gas at price levels which are competitive at the burnertip yet adequate enough at the wellhead to bring on sufficient supplies. That is not easy.

Current IPAA policy objectives as adopted at last month's mid-year meeting are as follows:

- Continue to battle against moves in Congress to increase the tax burden on natural gas producers;
- Resist actions by the FERC and Congress designed to arbitrarily reduce producer prices and alter two-party contracts directly or indirectly;
- Seek FERC action and legislation to increase market competition through contract carriage and any other actions designed to make it easier for buyers and sellers of gas to reach mutually advantageous agreements;
- Seek legislation to grant producers limited anti trust exemptions so that they might form cooperative marketing entities;
- Seek legislation to repeal the Fuel Use Act and incremental pricing in conjunction with legislation to give producers greater access to new markets;
- Seek legislation to end all wellhead controls on natural gas when contracts expire or are renegotiated;
- And continue to develop and expand programs to inform State utility commissions and consumers of the elements of public policy necessary to assure adequate future supplies of natural gas at affordable prices.

We commend Senator Nickles, Bradley, Johnston, Domenici and others for having introduced legislation designed to address one or more of the aspects of federal law still distorting the free flow of natural gas from wellhead to burnertip to all customers at rational prices.

Likewise we commend the Federal Energy Regulatory Commission for its bold action in issuing its current rulemaking. While producers have some problems with specifics of that rulemaking, we hope we can work within its framework to bring about constructive change.

In conclusion, we hope this Committee continues to prepare itself to take needed legislative action. The FERC is limited in some areas by its existing legislative authority. Because of that fact, its action may result in some unintended distortions and shortfalls and we hope you will be ready and willing to move to fill those legal gaps.

In the meantime, we remain available to counsel with you both formally and informally to solve problems. A healthy, expanding natural gas industry is too important to the basic economic foundation of our economy to receive less than our fullest attention and our best efforts.

Thank you.

Senator NICKLES. Thank you very much, Mr. Potts.
Mr. Balis.

STATEMENT OF STANLEY W. BALIS, ESQ., GENERAL COUNSEL, AMERICAN PUBLIC GAS ASSOCIATION

Mr. BALIS. Thank you, Mr. Chairman.

My name is Stanley W. Balis. I appear on behalf of the American Public Gas Association. I have already submitted prepared testimony and wish to simply summarize it here. I also wish to submit the executive summary of our comments on the NOPR when we file them with the Commission next Monday.

APGA is composed of publicly owned gas distribution systems located throughout the Nation. It is made up of various sized distribution systems, as large as Memphis, TN, but is basically composed of smaller, low load factor distributors who are served by one interstate pipeline company. We are the ultimate in captive customers in the interstate market.

However, while we are the ultimate in captive customers, we can do without the assistance that those in the producing industry would like to give us of freeing us from our interstate pipelines and leaving us adrift in the marketplace under schemes of common carriage or contract carriage.

Small distributors cannot afford to have a combination of deregulated wellhead prices in contract or common carriage. We must have the pipelines remain as buyers and resellers of natural gas.

The result of the proposals such as the FERC will not be the level playing field that the FERC so fondly refers to throughout its NOPR. Instead, we will have a worsening of the already existing bifurcated consumer market that now exists.

We today have a situation where the cheaper gas is going to industrial end users and those who have greater economic power to purchase gas in the field, but that gas is not going to the locked in type of user and to the small distribution system.

We hear so much about the $2.50 spot market price. We have to understand that that is for short-term gas, for gas from a particular well, or gas that is purchased on an as-available basis.

Small distribution systems, whether they be private or public, serve, basically, the highest priority residential and small commercial loads.

These loads have a basic inelastic demand. They use gas for heating and for cooking and for hot water.

These household type of users, while they certainly can conserve and have conserved and have put in insulation, et cetera, have a certain basic need for gas that they are going to have to pay for in a cold day in February, regardless of what the price is. There is not a true supply and demand curve that exists, where they simply turn off the heat and freeze, unless they have run out of money, which, of course, has happened to a number of elderly type of consumers in the residential market.

The distributors are a larger view of the same residential types of consumers. We are very low load factor. That is, for example, if a small distributor has a need for 5,000 MMBtu of gas on a peak day in February, it may have a need for only 1,000 MMBtu of gas on a summer day.

When you're in that type of situation, you cannot go to the spot market and ask to purchase natural gas. Instead, you must find a source that, one, is willing to provide that small amount of gas, because, even on a peak day, small distributors use what in this size marketplace would be considered very small. What process gas consumers' groups' spokesmen state about one member, one industrial system, using 200 million dollars' worth of gas in a year, the small distributors that compose APGA as distribution systems are dwarfed in size by that type of user and are pushed out of the marketplace. So the small distributor must find, one, a source that will provide that small amount of gas, will provide it on a long-term basis, will warrant that that 5,000 MMBtu of gas will be available in the wintertime, when it's needed to serve the human needs of customers, yet, on the other hand, will be able to balance its production, so that only 1,000 MMBtu need be delivered on a day like today, in the middle of the summertime.

This is something that a small producer can't provide for this kind of distribution system. It's something that the large producers certainly don't want to provide for the small distribution systems. But, even if there is someone out there in the producing market who wants to provide it, they certainly aren't providing it at $2.50 per MMBtu. That is not a price which reflects the kind of costs that small distributors have to pay for gas and the kind of costs they can expect to pay for the type of service they need if we go to some type of contract carriage that leaves them out there in the marketplace to fend for themselves.

Ironically, the source of this type of service that the small distributor needs and that the residential and small commercial consumer needs is the interstate pipeline. It's exactly the type of service that they have always provided.

They have balanced the loads. They have the storage facilities. They have the ability to take gas from different producers at different times. They have the ability, serving large geographic areas, to not have a coincidental peak on their entire system.

They are able to do these types of functions.

The problem is not that interstate pipelines have been the purchasers and resellers of gas. The problem is that they have not been instilled with the incentive to act as prudent purchasers.

We have permitted interstate pipelines, and, in fact, encouraged interstate pipelines, during the 1970's to become producers of natural gas, to either produce gas themselves or to set up producing affiliates. They, therefore, have become vertically integrated back to the wellhead.

They have taken on the interest of a producer-seller, rather than as a purchaser, because the prices that the pipelines have agreed to pay to nonaffiliated producers have become the basis of what they can agree to pay themselves, and, therefore, increase the overall corporate family profits.

So, the first thing that needs to be done is to eliminate this vertical integration of the pipelines in the producing business.

Second of all, at the other end, pipelines have been afforded automatic passthrough of all their gas costs in PGA filings with the FERC.

It's silly to talk in terms of a competitive market or any kind of supply and demand where we have an industry in which the largest cost—80 percent of all the costs that the pipeline incurs—are automatically passed through, regardless of what's going on in market conditions.

There is no competitive industry in which that type of occurrence takes place.

With that happening, with the incentive of the seller, because they're in the producing business, but no incentive of a prudent purchaser because of automatic pass-through of whatever they've paid for the gas prices, pipelines fell out of bed as far as worrying about what they paid for gas prices and keeping the price at a marketable level. Of course, we saw pipelines purchasing gas at $10 and hoping to resell it for $3. It just doesn't work.

But the problem is not because pipelines are purchasing and reselling gas. It's because the proper incentives don't exist for those pipelines.

Another very serious problem that would exist with contract carriage is what would happen the next time we have supply curtailment.

If we have gas supply curtailment, or when we had it in the past, at least the pipelines owned all the gas supply. They could then set up end use curtailment priorities and make sure that the shortage of the supply was allocated in a way that gas got to the homes for heating in the middle of the winter and cut off industrial users who had alternate fuel capability.

But the pipeline, under the contract carriage scheme, will not own the gas supply, and it will not have the legal authority to simply take gas that's been purchased by a large industrial boiler fuel user and say I'm hereby taking that gas and allocating that which I don't own to residential users in the middle of February. Where is the gas supply going to come from to assure that the heating loads will be met and that residential users won't go cold?

One thing that will happen is we'll set up a secondary market in which the industrial end users with great economic power who've locked up large gas supplies will be selling gas at the excessive prices that will have to be paid by residential users to buy out some of the gas that is under contract to those industrial users.

We'll be right back in a situation of not having adequate supplies of natural gas at just and reasonable prices with a locked in portion of the market.

APGA also opposes any type—assuming there is contract or common carriage—that includes the industrial end users. It must be limited to distributors of natural gas. It is clear that the only way that the locked in consumer is going to have a price since he has no market power of his own and since he has an inelastic demand, the only way that he's going to have a price which is at a proper level is if the sale to him is tied to the sale to the industrial user.

It's got to be clear to the producer that if he wants to sell gas that can be resold to industrial end users, that same price has got to be available for the locked-in user who is not able to send out that kind of market signal because he doesn't have the alternate fuel supply, he doesn't have an alternate supplier, even, of natural gas because it's behind a particular distributor.

Certainly no bypass should be allowed where an interstate pipeline can hook up directly to an end-user, bypass the distributor completely, and leave the distributor locked-in customers to bear, in addition to the gas costs, all of the fixed costs of the distribution system.

One other item which came up in the questions to the prior panel was the question of deregulation of old gas prices.

APGA is an organization which does support forever regulated gas prices.

APGA does not believe that there should be deregulation at the end of contracts, when contracts are renegotiated, or under definitions of production enhancement techniques or otherwise, because gas is gas, which is at low cost, which has already been drilled for, though some costs already exist, and to increase the prices especially now, when the price of gas overall is too high, makes no economic sense and would only result in excess profits to those producers who already have that gas.

I think it's interesting that, while a number of the industrial end users on the first panel discussed how they were opposed to having natural gas prices for old gas continue to be regulated, they also were very opposed to the concept of block pricing, where they didn't get the advantage of that old gas that was still regulated.

It seems to me that they would be very happy to have block pricing because it keeps the old gas for the locked in consumer who is not out there in the marketplace and yet does not in any way change the signal or give a distorted signal that that gas can be used to be averaged in with the block 2 gas, and, therefore, the block 2 gas prices would have to drop in order to be resold to the industrial end user.

The Natural Gas Supply Association spokesman said that the excess profit from the deregulation of old gas would be available for new drilling. One of the real problems with that is that: first, there's no requirement that it be so used; second, it's an admission, really, that the excess profits exist in the first place because they are going to be capturing more than the return that they should; but, third, not all producers have old gas. It's not out there disbursed among all producers in an equal way, and, in fact, the large producers have much more of it than the small producers.

Therefore, using that kind of dollars for new drilling cuts out new entrants into the market who have to get their capital through other sources, and it does not create a level playing field for producers either.

Thank you.

[The prepared statement of Mr. Balis follows:]

TESTIMONY ON BEHALF OF
THE AMERICAN PUBLIC GAS ASSOCIATION
BY STANLEY W. BALIS, ESQUIRE
BEFORE THE ENERGY REGULATION AND CONSERVATION SUBCOMMITTEE OF THE ENERGY AND NATURAL RESOURCES COMMITTEE OF THE UNITED STATES SENATE

July 9, 1985

I.

THE AMERICAN PUBLIC GAS ASSOCIATION'S INTEREST.

The American Public Gas Association ("APGA"), an organization composed of publicly owned natural gas distribution systems located throughout the United States, appreciates the opportunity to present its views to the Subcommittee regarding the current state of and factors affecting the natural gas market. APGA's address is P. O. Box 1426, 301 Maple Avenue, West, Vienna, Virginia 22180.

On behalf of APGA, I am Stanley W. Balis, Esquire, of the law firm of Miller, Balis & O'Neil, P.C., 1101 Fourteenth Street, N.W., Suite 1400, Washington, D.C. 20005. Because I and other members of my firm represent numerous publicly owned distribution systems both in the regulatory setting before the Federal Energy Regulatory Commission ("FERC" or "Commission") and the courts and in their contractual relationships with producers and industrial end users of natural gas, I am particularly familiar with the problems facing small distributors and residential and small commercial consumers in coping with today's natural gas market.

The typical publicly owned natural gas system is of small size, purchases gas at a low load factor, and is served by only one interstate pipeline company. In other words, publicly owned systems are generally the most locked-in, captive customers of interstate pipelines. Unlike the privately owned entities involved in the natural gas industry, APGA's members, as publicly owned systems, are concerned not only with their own viability as gas distribution systems, but also believe it is their duty to help protect the citizens of their respective communities as consumers of natural gas from excessive prices above just and reasonable levels.

II.

APGA OPPOSES DEREGULATION OF OLD GAS PRICES.

APGA opposes any attempt through legislation or through administrative action by the FERC to deregulate the price of old natural gas, which is now priced under Sections 104 and 106(a) of the Natural Gas Policy Act of 1978 ("NGPA"), 15 U.S.C. §§3314 and 3316(a). The producers of this natural gas have already received a fully compensatory, cost-based rate under the applicable area or national rate established by the Federal Power Commission (the FERC's predecessor agency), and, in addition, under the NGPA, have obtained non-cost based upward inflation adjustments in the price, even though the sunk costs to which the inflation adjustments have been applied have not increased and are not subject to inflation.

To deregulate these flowing gas prices would be to award excess profits to the producers of this natural gas, while at the same time imposing a totally unwarranted and unnecessary price increase on the consumers of natural gas. Certainly, at a time when the price of natural gas is already above market clearing levels (as discussed below), no action should be taken that would further increase the cost of gas to consumers. APGA opposes such deregulation of old gas prices, whether done in a straightforward manner through outright repeal of Sections 104 and 106(a) of the NGPA or through such gimmicks as reclassifying old gas as gas subject to "production enhancement" techniques.

III.

APGA OPPOSES TURNING INTERSTATE PIPELINES INTO CONTRACT CARRIERS OR COMMON CARRIERS.

APGA is also opposed to legislative and/or administrative attempts to impose contract carrier or common carrier status upon interstate pipeline companies, basically transforming them from purchasers and resellers of natural gas into mere transporters of natural gas. It may appear at first blush that APGA, as the representative of small, captive distribution systems, would be an avid supporter of freeing locked-in distributors from their particular pipeline supplier by requiring that interstate pipelines transport natural gas obtained from other sources. However, because of the realities of the structure and operation of the natural gas industry, removing interstate pipelines from their position as purchasers and resellers of natural gas, thereby leaving each individual distributor to obtain and balance its own gas supply, would be most detrimental to the small, low load factor distributors and the residential and small commercial consumers of natural gas.

The assumption underlying the various contract and common carrier proposals is that the only remaining anticompetitive part of the natural gas industry is the bottleneck created by the present buyer-reseller role of interstate pipelines. Thus, if this bottleneck were removed by permitting open and non-discriminatory transportation to all distributors and end users, then the natural gas industry structure supposedly would become workably competitive, such that the marketplace law of supply and demand would keep prices reasonable and supplies adequate for all consumers.

Unfortunately, this view of the natural gas industry is erroneous. Consequently, the removal of interstate pipelines from their historical role as buyers and resellers of natural gas would constitute not the removal of a stumbling block, but the removal of a necessary buffer between small distributors and residential and small commercial consumers without market power on the one hand and the large, integrated major producers of natural gas on the other.

A. The Pipeline - Producer Market.

Although prices for short-term, spot market natural gas have now declined, prices for firm, general system supply have still not decreased to market clearing levels. This is evidenced by the significant loss of loads suffered by interstate pipelines charging rates based on their current average, rolled-in cost of gas.

After the enactment of the NGPA in 1978, had these interstate pipelines exerted their market power as buyers of natural gas, they could have had a significant impact in offsetting the market power of the producers of natural gas, which would have been most beneficial to distributors and residential and small commercial consumers. Thus, the problem is not that interstate pipelines exist as purchasers and resellers of natural gas, but that these interstate pipelines generally have not acted as a prudent purchaser should act in the marketplace.

The reason for the interstate pipelines' failure to act appropriately as buyers of natural gas to keep the price of this commodity at the lowest just and reasonable level is that interstate pipelines are vertically integrated upstream to the wellhead. 1/ The pipelines therefore have had a

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1/ This vertical integration takes the form of gas production by the pipeline itself and/or by a production company affiliated with the pipeline.

shared interest with the producers as sellers because the prices paid by interstate pipelines to unaffiliated producers have been utilized to establish the upward limit that pipelines may agree to pay themselves or their affiliated producers. On the other side of the ledger, pipelines did not concern themselves with being able to bear the cost of the gas they were purchasing because the use of automatic purchased gas adjustment ("PGA") clause passthroughs -- permitted by the FERC --of prices paid to producers removed all of their incentive as prudent buyers.

Hence, what is needed is to give the pipelines the incentive to act as buyers by prohibiting the vertical integration of pipelines and their affiliates into the producing business and to eliminate automatic PGA filings with the FERC for increases in the cost of purchased gas.

B. The Residential And Small Commercial Consumers.

The concept of a workably competitive natural gas market is also seriously flawed because of the inelasticity of demand for a certain amount of natural gas by residential and small commercial consumers. Residential users will keep some level of heat in their homes on the coldest winter days, will have to cook their food, and will have to heat their water, regardless of the price of natural gas. These consumers lack the ability to simply switch to an alternate fuel. In fact, because they are located within the service territory of a particular distributor of natural gas, they are even unable to purchase natural gas from a different supplier.

Thus, with this significant part of the natural gas consuming market having an inelastic demand, it is simply not possible for just and reasonable prices for long-term, firm gas supplies to result at the wellhead from the unencumbered working of the marketplace.

C. The Pipeline In Its Roles As Buyer And Reseller Of Natural Gas Is Essential For Assuring Adequate And Reliable Firm Gas Supplies For Small Distributors.

Through their function as purchasers and resellers of natural gas, interstate pipelines also provide the necessary operating flexibility and load balancing for their respective distributor-customers. Pipelines have the ability to take gas from various sources, to utilize their storage facilities, and in most cases to serve wide geographic areas which results in noncoincidental peak days occurring on various parts of the pipeline system. This is especially essential for the small distributor-customers, which because of their small size do not have storage facilities and extensive peak shaving capability of their own. Yet because of their low load factors, these small customers have the most need for assistance in balancing their loads.

This flexibility to help balance loads and meet peak day and operational emergency situations that the pipelines possess is also of value to the large distributors of natural gas. Even a distributor that has more than one pipeline supplier still does not have the flexibility to deal with these problems that the larger and more broad based interstate pipelines have.

But the problems of the brave new world of contract and common carriage go much deeper for small distribution systems. The typical small distributor purchases natural gas at a fairly low average annual load factor. This results from the fact that it basically serves residential and small commercial loads, which have a much larger need for gas in the wintertime than during the summer. Thus, a small low load factor distributor with, for example, a 5,000 MMBtu per day contract demand may need that full 5,000 MMBtu on a peak day in February, but may only need 1,000 MMBtu on a summer day. If a small distributor -- whether it be Charlottesville, Virginia; Guymon, Oklahoma; Mesa, Arizona; Pikeville, Kentucky; or Springfield, Tennessee -- were to go into the field to purchase its firm gas supplies directly from producers, it would not be able to obtain its gas requirements at the spot market price, and in fact, might not be able to acquire its gas requirements at all.

While a producer may be willing today to sell whatever gas exists in a particular well or to sell gas on an as available basis for $2.50 per MMBtu or less, this type of purchase is not what the typical small distribution system requires. First of all, the small distributor may have such low requirements even on a peak day, that producers may not find it worthwhile to deal with such a distributor. But even if a number of small distributors banded together to purchase gas, while their total requirements would increase, their combined load factor would be just as low.

Thus, for example, they would be asking a producer to provide 4,000 MMBtu per day during the summertime but 20,000 MMBtu per day on peak winter days. They also would be requiring that the producer warrant that it will have the 20,000 MMBtu per day available on peak days during the winter since this gas will be needed for human needs, heating loads. Many producers would not even have the capability of dealing with this type of request for service, but even if a producer did, it certainly would not charge the spot market price, where firm gas supplies are being sought, and the producer is required to either find another purchaser for the summertime valley gas or in some other way balance its production to meet the low load factor requirements of the small distributors.

The point is that this is the function that interstate pipelines have historically played and continue to play for their small distributor-customers. The great majority of these distributors, like Tantalus, may reach for the $2.50 per MMBtu spot market gas, but can never obtain it. Thus, it is essential that pipelines continue in the role as viable purchasers and resellers of natural gas, but that the incentives for the pipelines to act in the interest of the producer-sellers, rather than as buyers, be eliminated.

Ironically, as can be seen from the above discussion, the concept of opening up the pipelines to become contract or common carriers, ostensibly to free the captive customers, would instead result in the most captive of the customers being trampled in the unregulated and anticompetitive marketplace. In short, the pipelines should be made responsible buyers, not removed as buyers.

One other very serious ramification of contract or common carriage is how curtailment will be administered if and when the next natural gas shortage occurs. Those who favor "letting the marketplace control" by creating a deregulated sales environment combined with contract or common carriage brush aside the question of how to administer curtailment by simply stating that there will be no future gas shortages once the marketplace takes over. On the contrary, the economic power of producers to increase prices through artificial shortages will be greatly enhanced once individual distributors are left vulnerable to fend for themselves in obtaining their firm gas supplies.

In the past, when curtailment became necessary and shortages of natural gas had to be allocated, the task was at least manageable since the particular pipeline owned all of the gas supply. It therefore could place end use curtailment priorities in effect that protected the highest priority consumers on its system. However, once the natural gas supplies are contracted for at the wellhead directly by particular distributors or end users, the pipeline will have no legal authority to take gas from a large boiler fuel user with alternate fuel capability which has purchased its own gas supply and reallocate what the pipeline does not own to distributors so that residential users will be able to heat their homes in the dead of winter.

Predictably, the larger, low priority end users with greater economic power would be able to obtain gas during a time of shortage while the smallest distributors and highest priority consumers are left without adequate supplies. Of course, if inelastic, captive consumers are cold enough, they can be forced to pay the excessive prices that would be necessary to free up volumes from the large low priority purchasers. In other words, the small distributors and residential and small commercial consumers will be left in the position where they are not assured of adequate supplies of natural gas at a just and reasonable price.

D. Any Contract Or Common Carriage Legislation Or Administrative Action Should Apply Only To Transportation For Distributors And Not For End Users.

APGA would stress that if any type of contract or common carriage is imposed on the pipelines by statute or by the FERC, it must be limited to distributors of natural gas. End users must not be permitted to purchase gas directly in the field and then require interstate pipelines to transport that gas for them. In the first place, additional purchasers in the marketplace may serve to drive prices up. Moreover, it is inappropriate to continue and expand the bifurcated market in which large, high load factor industrial end users purchase gas directly from producers at lower prices, while smaller, low load factor distributors are forced to pay higher prices for their gas supply. It is important for producers to recognize that the price that is charged to a pipeline or to a distributor must be sufficiently low that it can be resold to all consumers, including large, interruptible industrial end users. In this way, captive residential and small commercial consumers will not be required to pay excessive rates because of their inelasticity of demand.

Also, any contract or common carriage legislation must forbid an industrial end user from bypassing its natural gas distributor and hooking up directly to an interstate pipeline. Even if an industrial end user were permitted to purchase gas directly in the field and to obtain transportation by a pipeline to its distributor, it should at least contribute to the fixed costs of the distribution system so as to ease the burden upon the locked-in residential and small commercial consumers. Any changes in the regulatory scheme that would serve to burden further small distributors and residential and small commercial consumers without economic power in the marketplace must be rejected.

IV.

ACTIONS WHICH CONGRESS AND THE FERC SHOULD UNDERTAKE TO PROTECT CONSUMERS FROM THE ANTICOMPETITIVE CONDITIONS EXISTING IN THE NATURAL GAS INDUSTRY.

Rather than adopting any contract or common carriage proposal, Congress and the FERC should undertake certain actions to eliminate the disincentives for interstate pipelines to act in the buyers' interest in the marketplace and to help achieve long-term just, reasonable, and affordable gas prices for residential and small commercial consumers.

A. Prohibit Pipeline Production And Producing Affiliates.

First, Congress should prohibit interstate pipelines from producing or being affiliated with a producer of natural gas. This will remove the overall corporate incentive for a pipeline to agree to higher prices with unaffiliated producers in order to justify paying higher prices for the pipeline's own or affiliated production.

B. Eliminate PGA Clauses.

At the same time, the Commission should eliminate PGA clauses which permit pipelines to automatically pass through increases in their cost of purchased gas. Companies in competitive industries do not have the ability to automatically pass through their costs to consumers. In this case, pipelines' cost of purchased gas comprise about 80% of their total rates. If pipelines were unsure of their ability to collect from distributors the prices they agree to pay producers for gas, pipelines would be much more reluctant to execute contracts for gas at prices which are higher than the price at which that gas can be resold.

C. Void All Take-Or-Pay And Indefinite Price Escalator Clauses.

Congress or the FERC must act to void all take-or-pay clauses and indefinite price escalator clauses in contracts between producers and pipelines. Take-or-pay clauses are obviously thwarting pipelines from following a least cost purchasing strategy. If a contract is for the lowest priced gas, a pipeline should purchase 100% of the gas available thereunder without any take-or-pay requirement. On the other hand, if the gas under a particular contract is more expensive than other available supplies, a pipeline would only purchase that gas if it is forced to do so under a take-or-pay provision. Thus, by their nature, these clauses are intended to and do have the effect of creating behavior that is the antithesis of what would exist in a competitive market by forcing pipelines to purchase more expensive supplies while shutting in less expensive gas.

Indefinite price escalator clauses, such as most favored nations provisions and fuel oil price equivalency provisions, resulted in significantly higher prices under many contracts prior to January 1, 1985. Additional flyup did not occur upon partial deregulation on January 1, 1985, because the price of oil had decreased substantially by that date. If the price of oil had continued to rise or if it rises in the future, these indefinite price escalator clauses will cause even further flyups in the cost of purchased gas. Moreover, such provisions in gas contracts serve only to enhance the control of international oil prices over domestic natural gas prices.

V.

CONCLUSION.

In summary, the natural gas industry from the wellhead to the burner tip is not workably competitive. This lack of workable competition will not be remedied by bestowing contract or common carrier status upon interstate pipelines.

Because of the inherent inelasticity of demand of residential and small commercial consumers of natural gas, a truly competitive market may never be attainable in this commodity. However, the competitive situation as reflected in the price paid by consumers for natural gas can be markedly improved (i) if, instead of removing interstate pipelines from their historical role as buyers and resellers of natural gas, Congress would prohibit interstate pipelines from producing natural gas themselves or being affiliated with any producer of natural gas and would nullify all existing and prohibit all future take-or-pay and indefinite price escalator clauses in contracts between producers and pipelines and (ii) if the FERC would eliminate the automatic passthrough of purchased gas cost increases through PGA clauses and declare take-or-pay clauses to be unenforceable because they thwart the Natural Gas Act's requirement that pipelines follow a prudent, least cost purchasing strategy.

On behalf of APGA, I wish to thank the Subcommittee for the opportunity to express the Association's views on this most important subject.

Senator NICKLES. Mr. Balis, thank you.

Mr. Atwood.

STATEMENT OF JAMES D. ATWOOD, VICE PRESIDENT, NITROGEN MANUFACTURING, FARMLAND INDUSTRIES, INC., ON BEHALF OF THE FERTILIZER INSTITUTE

Mr. ATWOOD. Mr. Chairman, I am Jim Atwood, and I am employed by Farmland Industries.

Senator NICKLES. Would you pull the microphone up a little bit.

Mr. ATWOOD. Certainly.

Is that better?

I am employed by Farmland Industries as the vice president of Nitrogen Fertilizer Manufacturing.

I first became a resident of the State of Oklahoma in 1973, when I went to Enid, OK, to build the first ammonia plant that we have there.

I'm appearing here today on behalf of the Fertilizer Institute, sometimes known as the TFI. We're going to talk about how the natural gas industry affects the fertilizer industry.

In the end, I'll also present TFI's views on certain of the FERC's proposed rulemaking in RM 85-1.

As you are aware, the TFI is a voluntary, nonprofit, association, whose members represent about 95 percent of the fertilizer production in the United States.

In support of the nation's farmers, the products of the TFI members contribute to an abundant food and fiber supply.

Our members include manufacturers, traders, retail dealers, and distributors of fertilizer materials.

My company, Farmland, is a regional farm supply and marketing organization. Our mission is to improve the economic effectiveness of the Nation's farmers and farming operations.

We're owned, since we're a regional operation, by about 2,000 local associations. About 200 of those exist in the State of Oklahoma.

In Oklahoma, we consume a substantial amount of natural gas in the production of nitrogen fertilizers, and Enid is the flagship of our operation.

Fertilizers, as you know, are essential to our food chain. More than any other input to the farming operation, fertilizer has reduced the cost of food by increasing the productivity.

At the present time, something like 30 to 40 percent of the food production results from fertilizer application.

This relationship of natural gas to fertilizer and to our food chain we think is unique.

By using natural gas and water, we produce anhydrous ammonia. We take inert nitrogen from the air and convert it into anhydrous ammonia, which the plants can use. If the plants don't have a usable form of nitrogen, then, of course, there can be no life.

The larger and the more efficient ammonia plants that we have in the United States today consume about 36.4 million BTU's to produce a ton of ammonia.

In the current year, 1985, we expect that there will be about 16 million tons of anhydrous ammonia produced in the United States, and that will consume about 600 billion cubic feet of natural gas.

The cost of natural gas, of course, is of prime importance in affecting the cost of ammonia and the cost of our food.

The fertilizer industry in recent years has been heavily impacted by sharply rising natural gas prices. Natural gas is responsible for about 85 percent of the manufacturing cost of anhydrous ammonia.

Since 1970, the cost of natural gas has increased by about ten times.

The fertilizer industry has been very dependent on natural gas, and, as a result, TFI has been very interested in natural gas issues, and we produce policies on this matter.

In general, the TFI and Farmland support policies based on free market approaches.

The policy of the TFI, after the pricing provisions—the policy predicted that the future competitiveness of this particular industry would be enhanced by mandatory contract carriage, mandatory access to pipeline supplies of natural gas, so that could be easily transported from the point of purchase to the point of use.

During 1982 and 1983, the U.S. fertilizer industry was hit hard by high gas prices, and of course, the reduction in farmer demand and rising fertilizer imports.

By 1983, about 6 million tons of U.S. capacity had been shut down because of this cost price squeeze.

Part of that pressure has caused the fact that there have been no new ammonia plants built in the United States since 1978.

Many fertilizer manufacturers found that by purchasing natural gas under the usual resale arrangements from the pipeline distributors, they couldn't recover their variable costs. As a result, new arrangements for transportation had to be made to acquire lower cost gas and to keep the nitrogen plants operating.

These new transportation arrangements, of course, have taken many forms, and we utilize about all of those that are available. All of these forms, whatever form these new purchasing arrangements take, all are dependent on an open transportation system.

Transportation, we think, is the key which allows competitively priced natural gas to be moved from the point of purchase to the point of use.

Our company, Farmland's situation, we think has been typical of the fertilizer industry. As you know, we own and operate seven ammonia plants, located in Enid, OK, Fort Dodge, IA, Hastings, NE, Lawrence and Dodge City, KS, and Pollock, LA.

Some of these plants are located on interstate pipelines and others are located on intrastate pipelines.

During the past several years, the pricing arrangements furnished under our gas purchase arrangements with our pipeline suppliers became too expensive. As a result, Farmland was forced to shut down some of its plants for various periods of time.

By use of some of these special programs, which have allowed competitively priced gas to be directed to our facilities, we have reopened these plants and, for example, our largest plant at Enid, OK, where we have two ammonia plants and a solid urea plant, has been a benefactor of one of these programs.

The Oklahoma Corporation Commission has sanctioned a special program that directes market based producer gas to the Oklahoma fertilizer plants so that these plants can remain competitive.

Outside of Oklahoma—and we use a lot of Oklahoma gas in these programs—we have been able to use the FERC's blanket certificate program to transport natural gas to our Kansas and Iowa plants.

The availability of these natural gas sources by way of the transportation agreements is bringing competitive pressure to hold down the gas prices at our other manufacturing locations.

The experience of the fertilizer industry has demonstrated that competition among potential gas suppliers is a highly effective means of obtaining an economical supply of natural gas.

Gas transportation is important to the supply of natural gas. Thus, we think that it's essential to the domestic nitrogen fertilizer industry that the Commission's gas transportation programs be continued and improved to remove the regulatory impediments that restrict competition.

On May 30, 1985, the FERC issued a notice of proposed rulemaking which sets forth substantial changes in the regulations governing the transportation of natural gas. The Fertilizer Institute intends to generally support FERC's proposal for simplified transportation, conditioned to require nondiscriminatory access to pipeline transportation.

The TFI plans to support FERC's proposed certificate procedures which would facilitate competition between the pipelines.

While the Fertilizer Institute and its members might disagree on particular aspects of the FERC proposal, we think that the FERC should be commended for taking innovative actions which we think improve the competitiveness in the gas industry.

Thank you.

[The prepared statement of Mr. Atwood follows:]

STATEMENT OF JAMES D. ATWOOD

Vice President, Nitrogen Manufacturing
Farmland Industries, Inc.

ON BEHALF OF
THE FERTILIZER INSTITUTE

BEFORE THE
COMMITTEE ON ENERGY AND NATURAL RESOURCES
UNITED STATES SENATE

Hearings on
THE STATE OF THE NATURAL GAS INDUSTRY

July 11, 1985

Senator Nickles, we commend you for holding this hearing today, and we appreciate the opportunity to appear before you to discuss the state of the natural gas industry in relation to the fertilizer industry.

I am James D. Atwood, Vice President - Nitrogen Manufacturing for Farmland Industries, Inc. (Farmland). I am appearing today on behalf of The Fertilizer Institute (TFI). TFI is a voluntary, non-profit association, whose members represent approximately 95 percent of the domestic fertilizer production in the United States. In partnership with our nation's farmers, fertilizers from TFI's members contribute to our abundant supply of food and fiber. TFI's membership includes producers, manufactuers, traders, retail dealers and distributors of fertilizer materials.

Farmland is a regional farm supply and product marketing cooperative whose mission is to improve the economic status of farmers and farming operations. Farmland is owned by over 2,000 local cooperatives. The 19 states served by Farmland include Oklahoma, where we consume substantial quantitites of natural gas, used in the production of nitrogen fertilizers. In addition, grain drying, food processing, and irrigation affect our members and their local cooperatives.

Natural Gas and the Fertilizer Industry

In discussing natural gas and the fertilizer industry, we should begin with the explanation that fertilizers are critical to our food supply and to our food chain. Fertilizers provide essential nutrients that enter our food chain system and go the course all the way to the hamburger we may eat, the bread in our sandwich, or the milk we drink. Fertilizer, more than any other input to the farming operation, reduces the cost of food by increasing farm productivity.

The relationship of natural gas to the fertilizer industry, and to our food chain, is unique. By using natural gas and water in the commercial production of anhydrous ammonia, we convert inert nitrogen of the atmosphere into a form which plants can use to promote growth and provide protein in our food products. Only when nitrogen is converted from its inert state in the atmosphere to forms which plants can use, can it become useful in the production of essential protein for human and animal life. Without protein, there is no life.

Thus, fertilizers are essential to this nation's food supply. Not only do fertilizers provide nutrients which directly enter the food chain for eventual consumption, but fertilizers are an essential input for efficient crop production. Information from the United States Department of Agriculture shows that 30-40 percent of our present crop production results from the application of fertilizer.

In recognition of the critical role natural gas plays in the fertilizer production for the agricultural sector, Congress included fertilizer production in the definition of "essential agricultural use" set forth in the Natural Gas Policy Act (NGPA), and thereby provided a priority to fertilizer production in times of curtailment and a statutory exemption from incremental pricing.[1]

The basis of virtually all synthetically produced nitrogen fertilizer is ammonia. From ammonia, which we produce with natural gas, air and water, the industry produces urea, ammonium nitrate, ammonium sulfate and ammonium phosphates. For the basic product of ammonia, however, approximately 95 percent of our production of this product is dependent upon natural gas.

In centrifugal ammonia plants, the larger, more efficient plants presently in use, the industry in CY 1984 has just reported an average use of natural gas equivalent to 36.4 million Btu's per ton of ammonia.[2] An annual production of 16 million tons of ammonia is what we estimate for 1985. Production at this rate will consume about 600 billion cubic feet (Bcf) of natural gas, and lays the foundation for the production of million of tons of protein we consume at the other end of the food chain. A paper prepared for the Natural Gas Supply Association stated that "overwhelmingly the most important link between natural gas and agriculture is through fertilizer, particularly ammonia, as a source of nitrogen."[3]

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[1] 15 U.S.C., Sections 3346(b), 3391.

[2] TFI Energy Use Survey, CY 1984.

[3] B. Gardner, Impact of Natural Gas Deregulation on the Farm and food Sector 1 (1982).

Because we emphasize very heavily the importance of ammonia as a source of nitrogen in our food chain, the cost of natural gas is of prime importance. The fertilizer industry has been heavily impacted in recent years by sharply rising costs of natural gas.

Natural gas is now responsible for up to 85% of the total manufacturing cost in all but those few plants still on low cost natural gas. Since 1970, the cost per unit of natural gas for ammonia production in the United States has increased nearly 10 times.

TFI's Policy on Natural Gas

In view of the importance of natural gas to the fertilizer industry, the Board of Directors of The Fertilizer Institute adopted in 1982 a policy on natural gas. It has been reviewed annually since then and, most recently, reaffirmed November 1984. In retrospect, points in this policy dealing with natural gas pricing and transportation have hit the mark so well that we think they are applicable to this hearing. The policy states:

1. Continuation of the NGPA is the least desirable form of natural gas decontrol for the fertilizer industry. In addition, reimposition or extension of price controls is adverse to the interest of the fertilizer industry.

2. The most desirable form of decontrol would be:

   A. Phased decontrol of all categories of natural gas by a date certain, and

   B. Voluntary revision of the indefinite price escalator and take-or-pay provisions of purchase contracts between pipelines and gas producers.

3. The future competitiveness of the industry would be enhanced by:

   A. Establishing a mandatory mechanism to allow fertilizer producers access to the interstate pipeline system to move gas that they can purchase from the point of purchase to their plants, and

   B. Allowing unrestricted access to natural gas under expired contracts and natural gas in the Outer Continental Shelf.

This policy represents a free-market approach to an industry which has been heavily regulated. The TFI policy recognizes that competition among gas suppliers is the only viable means to provide economic gas supplies for the fertilizer industry.

The Importance of Gas Transportation

During 1982 and 1983, the United States nitrogen fertilizer industry was hit very hard by high gas prices, a reduction in farmer demand for nitrogen fertilizer, and rising fertilizer imports. It has been estimated that by mid-1983, over 6 million tons of ammonia capacity (30 percent of total capacity) had been shut down as a result of this cost-price squeeze.[4] This pressure of increasing natural gas costs on ammonia production also has resulted in the fact that the United States has not built a new ammonia plant since 1978. Since 1981, the United States has been a net importer of nitrogen, and for the year ending June 30, 1984, we were a net importer of 1.9 million tons of nitrogen, equivalent to the nitrogen of 2.3 million tons of ammonia.

Many fertilizer manufactuers found that by purchasing natural gas under the usual resale arrangements from pipelines and distributors, they could not cover the variable costs of operating their plants. As a result, new arrangements based upon gas transportation have been utilized to acquire natural gas at costs lower than otherwise possible with traditional marketing of natural gas by pipelines, and hence to keep nitrogen plants operating and to reopen closed facilities.

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[4] John Douglas, Fertilizer Outlook -- 1984

These new transportation arrangements have been utilized to permit competitive forces to reduce gas prices to fertilizer manufacturers. While these new arrangements have taken a number of forms, TFI members are now extensively relying upon the FERC's blanket certificate program, producer special marketing programs, direct purchases of natural gas from the Outer Continental Shelf (OCS), transportation of natural gas under NGPA Section 311, importation of natural gas from Canada, and special purchase programs of pipelines and distribution companies. All of these new arrangements are dependent on an open transportation system, which will allow competitively-priced natural gas to be moved from the point of purchase to the point of use.

Farmland's situation has been typical of the fertilizer industry. Farmland owns and operates seven ammonia plants located at Enid, Oklahoma; Fort Dodge, Iowa; Hastings, Nebraska; Lawrence, Kansas; Dodge City, Kansas; and Pollock, Louisiana. Some of Farmland's plants are served by the interstate pipeline system, while others are connected to intrastate pipelines. During the past several years, the price of natural gas furnished under gas purchase arrangements with our pipeline suppliers became too high. As a consequence, Farmland was forced to shut its plants for various periods. By use of special programs, which have allowed competitively-priced gas be directed to our facilities, we have reopened these facilities. For example, at our largest nitrogen manufacturing complex located at Enid, Oklahoma, we operate two ammonia plants and a solid urea plant. The Oklahoma Corporation Commission has sanctioned a special program to direct market-based producer gas to Oklahoma fertilizer plants so that these facilities will remain competitive. In addition, we have utilized the FERC's blanket certificate program to transport natural gas to our Kansas and Iowa plants and the availability of natural gas via transportation is bringing competitive pressure to hold down our gas costs at our other manufacturing locations.

The experience of the fertilizer industry has demonstrated that competition among potential gas suppliers is a highly effective means for obtaining an economical supply of natural gas. Gas transportation is important to ensure the availability of competitive options. Thus, it is essential to the domestic nitrogen fertilizer industry that the Commission's gas transportation programs be continued and improved to remove regulatory impediments that restrict competition.

On May 30, 1985, the FERC issued a Notice of Proposed Rulemaking which sets forth substantial changes in the regulations governing the transportation of natural gas by pipelines. TFI intends to generally support the FERC's proposal for a simplified transportation program conditioned to require nondiscriminatory access to pipeline transportation. In addition, TFI plans to support the FERC's proposed optional certificate procedures which would facilitate competition between pipelines. While TFI or its members might disagree with particular aspects of the FERC proposal, this agency should be commended for taking innovative actions to promote competition in the gas industry.

We appreciate your review of the situation in the gas industry and your consideration of our views.

Senator NICKLES. Thank you very much, Mr. Atwood.

Dr. Cooper.

STATEMENT OF DR. MARK N. COOPER, DIRECTOR OF ENERGY, CONSUMER FEDERATION OF AMERICA

Dr. COOPER. Thank you, Mr. Chairman.

Unlike some of the others, I think I will take my testimony and submit it to FERC as our comments on their rule.

The runup in gas prices in 1980–1982, the subsequent downward pressures on world oil prices, and a short-term overdeliverability of supply have turned January 1, 1985, once a much feared date, into a nonevent.

However, the relative quiet at the wellhead has been replaced by an uproar downstream.

Traditional transportation relationships have begun to change, driven by a permanent reduction in demand and an increase in the price sensitivity of some end-use markets.

Responding to these changes, the Federal Energy Regulatory Commission has proposed a comprehensive administrative deregulation of pipelines.

Unfortunately, the FERC proposal will be to the detriment of residential and commercial consumers who have the fewest supply options. FERC has sprinkled the word "nondiscriminatory" throughout a plan; it has absolutely no mechanism for actually preventing discrimination.

FERC proposes to end control of pipeline purchasing practices by breaking the link between the current transportation monopoly and acquisition of gas at the wellhead.

Anyone will be able to go into the gasfield and purchase gas.

FERC further proposes to create a market in transportation services by allowing anyone to strike a number of potential transportation deals.

The problem lies in the questionable ability of anyone to buy gas in the marketplace under the FERC's scheme.

Although the current opinion is that the wellhead is workably competitive, there are those of us who still have concerns.

The current euphoria about the viability of the wellhead market stems primarily from short-term excesses of supply and deliverability. That condition is not likely to persist.

As those pressures are reduced, we will return to a situation in which the bargaining power shifts back to the producers.

The wellhead is a vulnerable market, characterized by a number of special features, including joint ventures, ownership of substitute products, relatively limited quantities of undedicated supply, and, of course, an international oil market that is far from perfectly competitive.

As a result of these features, the natural gas wellhead market may be less workably competitive than it appears at first glance.

At the same time, it must be recognized that the citygate market is extremely concentrated. In the gas transportation industry, about 60 percent of all local distributors have no alternative supplier whatsoever. By volume, over half of all local distribution companies are served by less than three transportation suppliers. And, even where there are three or four such supplies, each tends to have the capacity to supply only a part of the market. Thus, the ability of distributors to expand the supply of transportation services by playing pipelines off against one another is limited.

In the long run, FERC hopes that its new policy of gas-on-gas competition and expedited entry to markets will create more alternative sources of transportation supply.

However, that is not likely for local distribution companies and not likely in the short term.

The essential discipline in the FERC's scheme, therefore, must come from the demand side of the market. Yet, the elasticity for demand of natural gas is not very high. It is estimated at about one in the long term. That's far lower than most other industries in which we deal with nonessential commodities.

In sum, the risk which FERC says will discipline pipelines is extremely feeble. The rewards could be very great, however.

If pipelines use low estimates of representative volumes and make large sales, they can make excess profits on sales in excess of those representative volumes.

None of the benefits of utilizing additional capacity accrue to the consumers already on the system. Only those who can make the discount deals with the pipeline receive the benefits.

This is simply a scheme of incentive regulation in which pipelines will not be closely scrutinized by FERC, will almost certainly win, and will also have the power to decide which consumers win, which consumers benefit.

A market structure that will insure access for customers who demand relatively small quantities of firm, long-term sales, and who have few transportation alternatives, is no certainty. Yet, these are the customers most in need of protection from the abuse of market power.

The threat of tight supplies will render these customers vulnerable in bargaining for gas at the wellhead and in bargaining for transportation services. Without adequate market and regulatory structures, de facto price discrimination will occur. But there is only small justification for price discrimination at the wellhead and only slightly more for price discrimination in transportation.

Now, FERC proposes a theory to prevent cross-subsidy. But the theory of pricing it has embraced is vacuous and constitutes complete abdication of regulatory responsibility. The theory, as we have witnessed it in the telephone industry, states that any price above incremental cost and below stand-alone cost is subsidy free.

In natural gas transportation, that range is between 10 cents and $1 for markets that are relatively distant from gasfields. The monopolist is then given the flexibility to decide who pays the dime and who pays the dollar.

Such decisions cannot be left to monopolists, as FERC has proposed to do.

FERC is to be applauded for one of its proposals. It has finally accepted Congress' intention to allocate the economic rents of old gas to historical firm sales customers. That this was Congress' intention in the NGPA is clear, not only in the fact that it continued controls on old gas, but in the fact that it also created a mechanism to which it intended to allocate the cost burden of new gas onto other classes of consumers.

Today, as in 1978, there is no reason to double, triple, quadruple, quintuple, the price of 50 trillion cubic of gas, which was found decades ago at virtually no cost, in order to find 5 or 10 trillion cubic feet of new gas.

The balanced approach remains the control of rents and the targeting of incentives.

In sum, the FERC proposal solves the short-term problems at the pipelines and some producers and provides long-term benefits for large consumers with flexible loads.

With the exception of the fact that FERC has finally decided to implement congressional intentions in the distribution of the rents from old gas, residential consumers get the worst of the FERC proposal. They will be at a serious disadvantage in bidding for gas in the field, and they are treated as the captive cash cows in the transportation market.

Thank you.

[The prepared statement of Dr. Cooper follows:]

Consumer Federation of America

TESTIMONY OF

DR. MARK N. COOPER

DIRECTOR OF ENERGY,

CONSUMER FEDERATION OF AMERICA

before the

SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION

of the

ENERGY AND NATURAL RESOURCES COMMITTEE,

UNITED STATES SENATE

on

RECENT DEVELOPMENTS IN THE NATURAL GAS INDUSTRY

JULY 11, 1985

1424 16th Street, N.W., Suite 604 • Washington, D.C. 20036 • (202) 387-6121

Mr. Chairman and Members of the Committee,

My name is Dr. Mark. N. Cooper. I am Energy Director of the Consumer Federation of America (CFA). CFA is composed of 200 consumer, senior citizen, low-income, union, farm, public power, and cooperative organizations representing more than 35 million people.

I appreciate the opportunity to appear before you today to testify on recent developments in the natural gas industry. As always, the natural gas industry appears to be on the brink of a major change.

The run-up in gas prices in 1980-1982, the subsequent downward pressures on world oil prices and a short term over-deliverability of supply have turned January 1, 1985 -- once a feared date -- into a non-event. However, the relative quiet at the wellhead has been replaced by an uproar downstream. Traditional transportation relationships have begun to change, driven by a permanent reduction in demand and an increase in the price sensitivity of end-use markets.

We now have before us the most comprehensive proposal for administrative regulatory reform in the history of traditionally regulated public utilities. The FERC proposal certainly rivals the actions of the Civil Aeronautics Board in 1974-1976 and the actions of the Federal Communications Commission in 1978-1982. In many senses it equals the legislative regulatory reform enacted by Congress for the railroad industry in 1980.

I mention these other industries because CFA has been actively involved in the process of regulatory reform in a number of them. More importantly, it is time for Congress and the administrative agencies of the executive branch to begin to refine their approach to regulatory reform proposals in light of the experience with deregulation in the past decade. We have acquired sufficient knowledge about the process and impact of regulatory reform to stop relying on pure theory.

In my remarks today I will begin with some observations on the general trends that we see emerging in other industries, trends which can be expected in the natural gas industry. These touch on the issues of industrial concentration, price discrimination, cross-subsidy, low density markets, and economic rents. I will them discuss several key points in the new regulatory structure proposed by the Federal Energy Regulatory Commission (FERC) in light of these observations.

Experiences in other industries clearly indicate that the

FERC proposal will be to the detriment of the residential and commercial consumers who have the fewest supply options. Smarting from a defeat in the courts, FERC has sprinkled the word non-discriminatory throughout a plan which has absolutely no mechanism for actually preventing discrimination. The residential consumer will be the loser in the FERC scheme, not because contract carriage and expanded reliance on competition cannot work, but because the scheme proposed by FERC is poorly conceived and riddled with contradictions.

STRUCTURES AND TRENDS IN DEREGULATED MARKETS

INDUSTRIAL CONCENTRATION

Traditional economic theory as applied to industrial organization should still guide our decisionmaking process. By traditional economic theory I mean the school of thought that concerns itself with the actual number of firms in an industry and the social and economic effects of the abuse of market power. Newer theories that maintain that a lack of competition is not a matter of serious economic concern or that potential competition is adequate to ensure workable markets are not compelling in light of a decade of deregulation. The number of firms actually competing in a market remains an important predictor of price/cost performance.

The relevance of this observation to the natural gas industry is clear. Whenever the wellhead market is discussed, we invariably hear the argument that concentration ratios are low and barriers to entry are not great, even measured at the level of individual fields. This leads to the assertion that the wellhead market is workably competitive. Regardless of what one believes about the wellhead market, at least the debate is carried out in terms of standard market structural analysis.

Yet, when attention turns to the city-gate market that form of analysis disappears. Without explaining why the assumptions and conclusions of traditional market structure analysis no longer apply, we suddenly hear arguments that the presence of more than one pipeline, or the elasticity of demand, is adequate to ensure a workable market. We would not accept those arguments at the wellhead, or in other industries, and we should not accept them for the city-gate market.

We should insist on the tried and true measures of market structure. By those measures, the city-gate market is extremely concentrated -- one of the most concentrated industries in the entire economy.

PRICE DISCRIMINATION

A second observation that emerges from the decade long experience with deregulation is that price discrimination is a powerful force in markets with pricing flexibility. By price discrimination (or differential pricing) I mean the setting of different price/cost ratios depending on factors other than costs. This is frequently called demand-based or market-based pricing.

One of the strongest motives of an unregulated market is to establish the highest price that the market will bear. This entails identifying as many different segments or classes within a market, based on their different willingness to pay, so that different prices can be charged in each.

Under certain natural monopoly conditions, price discrimination is economically justified. However, where competition is weak, it is extremely difficult to distinguish economically justifiable price discrimination from plain old monopolistic price discrimination. Economically justified price discrimination lowers prices in order to increase output. Monopolistic price discrimination raises prices to maximize profits and, incidentally, lowers output.

In the natural gas industry this is an extremely complex issue. Transportation services will reflect a variety of justifications for discounting services. Cost differences in providing services to high volume users and some market-based price discrimination can be justified. Neither of these justifications extends to the wellhead market. Nor, obviously, should we accept exploitative pricing. A great deal of vigilance is called for when pricing flexibility is granted.

CROSS-SUBSIDY

My third observation is closely related to price discrimination. In the early period of pricing flexibility in industries that remain subject to a revenue constraint there is a tremendous amount of cost shifting (this is certainly true of the railroad and telecommunications industries). This cost shifting is inevitably defined as the creation of a cross subsidy by those whose rates go up and the elimination of a cross-subsidy by those whose rates go down.

If one defines cross-subsidy as prices set below cost, one encounters an extremely complex definitional problem. In telecommunications, where the issue has been subject to the greatest scrutiny, the answer is hopelessly entangled in competing theoretical, accounting, and engineering definitions of the term "cost."

The theory of pricing that has taken hold in the railroad and telecommunications industries is vacuous and constitutes a complete abdication of regulatory responsibility. The theory states that any price higher than incremental cost and lower than stand-alone-cost is subsidy free. This solves absolutely nothing. In the telecommunications industry that means a price anyplace between roughly $10 and $50 per month. In natural gas transportation the range would probably be between $.10 and $1.00 per MCF in markets distant from gas fields. The monopolist is then given the flexibility to decide who pays the dime and who pays the dollar.

Any change in the regulatory allocation of costs will, of necessity, unleash this debate. This has been the case for almost two year in the natural gas industry and it can only become more hotly debated in light of recent FERC proposals.

LOW DENSITY MARKETS

The process of price discrimination and cost shifting inevitably works to the disadvantage of less dense parts of the network. Service declines and/or prices increase in these markets. Part of this is economically rational -- reflecting cost differences. Some of it may reflect the exercise of market power. All of it remains a legitimate matter of social concern.

The fears of smaller natural gas distributors and consumers that they will not be able to compete at the wellhead or will not be favored with attractive deals for transportation are not without foundation.

ECONOMIC RENTS

The shift from cost-based to competitive or market-based pricing inevitably creates or destroys huge economic rents, unless explicit steps are taken to control them. It creates rents where they are based on the underlying scarcity of natural resources. It destroys them where they were based solely on scarcity enforced by regulation.

Economic rents are a deeply troubling phenomenon for our society. We do not expect them to be large in most competitive markets because competition and technological innovation are supposed to erode economic rents. Whenever we encounter them, primarily in natural resource markets, notions of social justice move us to redistribute them. This is especially true where efficiency losses are small compared to the magnitude of wealth transfers.

The rents associated with old gas have been the focal point of almost a decade of debate and they will most likely continue to be a thorny issue. Locational rents will not be so hotly debated.

TRENDS AND STRUCTURES IN THE NATURAL GAS INDUSTRY

The Notice of Proposed Rulemaking issued by FERC on May 30, 1985 provides a convenient vehicle for integrating these observations into the natural gas industry. The essence of that proposal is a three part tariff -- an old gas part, a new gas part and a transportation part. The FERC proposes that this tariff support a scheme of quasi-voluntary, quasi-mandatory contract carriage.

The scheme would be quasi-voluntary because pipelines need not enter the program at all. It would be quasi-mandatory because once they allow contract carriage to a single shipper, they would have to provide it on a non-discriminatory basis to all shippers.

In order to keep the program non-discriminatory and to make it economically viable, FERC felt obliged to create a number of rules, but the essence of any regulatory scheme is the selection of tariffs. Each of the parts of the tariff is intended to make the transportation market more workably competitive.

REGULATORY CONTROL OF THE ECONOMIC RENTS OF OLD GAS

In the first part of the tariff FERC proposes to allocate the economic rents to historical, firm sales customers of pipelines. Existing firm sales customers of the pipeline would be allocated low cost old gas supplies in proportion to their demand in 1982, 1983, and 1984. FERC states that Congress "apparently intended" to allocate these rents to these customers.

There is no doubt that Congress intended for these rents to be allocated to firm sales customers. Not only did Congress continue controls on old gas, it also created a mechanism (incremental pricing) through which it intended to allocate the cost burden of new gas onto other classes of consumers. After resisting this Congressional intention for almost a decade, FERC is to be commended for finally coming up with a plan of implementation that might actually get the job done.

Congress appeared to have in mind both equity (minimizing price increases for a necessity) and efficiency (transmitting price signals by showing price increases to the most price-sensitive market segment first). This scheme has been roundly criticized for its supply-side inefficiencies. Controls on old gas reduced incentives to maximize production from old gas fields. The charge is certainly correct, and also irrelevant.

Congress consciously provided incentives to stimulate production of other types of gas. It created potential avenues for specific targeted incentives to be allowed for enhanced recovery of old gas. Today, as in 1978, there is no reason to double, triple, quadruple or quintuple the price of fifty trillion cubic feet of gas, which was found decades ago at virtually no cost, in order to find five or ten trillion cubic feet. The balanced approach remains the control of rents and the targeting of incentive.

MARKET CONTROL OF THE PRICE OF NEW GAS

The second block in the tariff allows contract carriage to discipline the price of decontrolled gas. The goal is to end control and inspection of pipeline purchasing practices by breaking the link between the current transportation monopoly/oligopoly and acquisition of gas at the wellhead. Anyone will be able to go into the gas field, purchase gas, and be allowed to transport it on a non-discriminatory basis.

Once anyone can routinely purchase gas, the reasoning goes, no one will be able to sell gas at above market clearing prices. Moreover, with a specified allocation of old gas, each individual should have an incentive to reduce the cost of new gas, since savings can be achieved on a dollar-for-dollar basis.

In addition to neutralizing old gas, FERC would like to wipe the slate clean with respect to existing new gas contracts. Pipelines will be able to buy their way out of unrecoupable obligations on bad contracts, provided the price is reasonable. Consumers may complain that pipelines should be forced to swallow imprudently incurred costs. Producers may argue that pipelines should meet their legal obligations.

The pipelines have certainly been made an inviting offer by FERC. They are treated as innocent victims being let off the hook. How they came to be the victims is not clear, yet, wiping the slate clean may be in the interest of consumers and many suppliers.

The real problem lies in the ability of "anyone" to buy gas in the marketplace. Although the current opinion is that the wellhead is workably competitive, there are those of us who still worry about the viability of the wellhead market. It is a vulnerable market, characterized by special features including joint ventures, ownership of substitute products, relatively limited quantities of "undedicated" supply, and an international oil market that is far from perfectly competitive. As a result of these features, the natural gas wellhead market may be considerably less workable than it appears at first glance.

The current euphoria about the viability of the wellhead market stem primarily from the short term excess of deliverability. That condition is not likely to persist. As those pressures are reduced, we will return to a situation in which the bargaining power shifts back to the producers. A market structure that will ensure smaller consumers access to gas at reasonable prices is no certainty. A very large part of the demand in the market is made up of customers who demand relatively small quantities of firm, long term sales and who have few transportation alternatives available. When supplies are tight, the obligation to serve creates much greater constraints on bargaining than the need for cashflows.

The threat of tight supplies will render them vulnerable in bargaining for gas at the wellhead and in bargaining for transportation services. Without adequate market and regulatory structures, de facto price discrimination will occur, but there is only small economic justification for price discrimination in the wellhead market and slighlty a little more justification for price discrimination in the transportation market.

TRANSPORTATION

In theory, mandatory contract carriage will help to discipline bidding at the wellhead by removing the market power of the bottleneck facility. However, that does not mean that the bottleneck in transportation will be removed. It does not mean that transportation rates should be deregulated, or that the rate of return should not continue to be constrained.

FERC proposes to establish rates based on costs allocated across a representative set of volumes of gas. With costs recovered only on specific volumes, FERC argues that pipelines will risk underrecovery of revenues if volumes fall short. Therefore they will be driven to engage in cost minimization to ensure maximum volumes.

This approach is conceptually and technically flawed.

Conceptually, in most markets, the risk of undercollection of revenues stem from two sources. There is a supply-side risk and a demand-side risk. If a firm endeavors to raise prices above costs, competing firms will expand their output and steal the sales of the offending firm. At the same time, if prices rise, consumers will reduce their demand. The offending firm lacks market power where the loss of sales is so large that profits decline.

In general, the supply-side risk of lost sales is seen as the most important (that is why the number of suppliers receives so much attention in industry structure analysis). Yet, in the gas transportation industry, about 60 percent of all local distributors have no alternative supplier whatsoever. Even where a few suppliers are available, each tends to have the capacity to supply only a part of the market.

Thus, the ability to expand supply is limited. There is little or no potential supply-side response in transportation services. In the long run FERC hopes that its new policy to allow gas-on-gas competition and expedited entry to markets will create more alternatives sources of supply. However, that is not likely for local distribution companies and not likely in the short term.

The essential discipline in the FERC scheme must come from the demand-side. Yet, the elasticity of demand for natural gas is not very high. It is estimated at about one in the long term, which is far lower that most industries which deal in non-essentials.

In sum, the risk which FERC says will discipline pipelines is extremely feeble. The rewards could be very great. If pipelines use low estimates of representative volumes and make large sales, they will make high profits. They have every incentive to underestimate sales (they have the same incentives in estimating the unrecoupable contract costs they would like to settle).

FERC has simply shifted all the difficult problems of cross-subsidy and price discrimination into the question of representative volumes. Choosing representative volumes less than 100 percent of capacity over which to allocate costs gives pipelines potentially excess capacity to play with. They can make excess profits on sales in excess of representative volumes. FERC has not proposed to adjust the costs allocated to the representative volumes, if pipelines do fill capacity. Once representative volumes have been chosen, none of the benefits of utilizing additional capacity accrue to the consumers already on the system. Only those who make the "discount" deals with the pipeline receive the benefits.

By choosing their representative volumes carefully, pipelines have nothing to lose and everything to gain. They can build a relatively certain rate of return by a low estimate of representative volumes. They can then bargain with more price sensitive transporters at the margin for excess profits. Since they will be disciplined only by the demand-side of the market, they will be living in a relatively risk free world.

This is simply a scheme of incentive regulation in which not only do pipelines almost certainly win, they also have the power to decide which consumers will benefit. The concerns that small, firm consumers have expressed can only be increased by this approach to marketing transportation services. Given their lack of bargaining leverage, they are least likely to be able to strike the necessary "deals."

CONCLUSION

The selective discounting of services has been defended in all of the transportation and communication industries by the argument that it is better to discount and receive some contribution to the fixed costs of the system than to lose the business altogether. Here we have scheme in which selective discounting is totally at the discretion of the pipelines and, at the margin, it contributes only to pipeline profits.

The flaw in the scheme is the assumption that the transportation market is workably competitive. Only when there are adequate alternative sources of supply will this be the case. FERC's proposal to allow free entry and exit from the transportation industry may help to increase the number of alternatives. However, this is a misapplication of exotic theory to the gas industry. The mere threat of entry or exit is not enough to discipline markets where entry barriers are significant. That was the first observation I offered. Until actual competition exists, markets cannot be expected to discipline themselves.

The FERC proposal solves the short term problems of the pipelines and some producers, and provides long term benefits to large consumers with flexible loads. With the exception of the fact that FERC has finally decided to implement Congressional intentions in the distribution of rents from old gas, the residential consumer gets the worst of the FERC proposal. Residential consumers will be at a serious disadvantage in bidding for gas in the field market and they are treated as the captive, cash cow in the transportation market.

I appreciate the opportunity to appear today. FERC may iron some of these problems out in specifying detail of the program, judging from the direction that FERC has proposed, I suspect that Congress will continue to be confronted with difficult and important decisions in the natural gas industry.

Senator NICKLES. Thank you, Dr. Cooper. I'm sure FERC will be pleased to hear that you so warmly endorse them. [General laughter.]

Senator FORD. Well, he did. He said one was good. [General laughter.]

Senator NICKLES. Mr. Potts, representing the IPAA, do you know how many active rigs are running in the country today, say, as compared to a couple of years ago?

Mr. POTTS. We're down from our high of 45 at the end of 1981.

Senator NICKLES. Forty-five?

Mr. POTTS. Forty-five hundred. We're down to approximately 2,000 today. It's over a 60-percent decrease.

That speaks to Mr. Lawrence and his earlier testimony, who talked about this tremendous supply of natural gas and how, during the 1981 and 1982 periods, we maintained our supply by adding new wells.

It's very apparent to anyone, if you look at the drop in rig activity, you know, you don't have production if you don't drill wells. This whole issue of supply is left unaddressed at all in FERC's proposed rulemaking.

So, there is a serious consequence coming down the road by what is not happening today, and that is wells are not being drilled.

Senator NICKLES. You mentioned the total number of rigs is 60 percent less than what it was just a couple of years ago.

Do you happen to have those figures, by any chance, on the number of active rigs that were running, say, in the gas industry 2 or 3 years ago, compared to what they are today?

Mr. POTTS. No, I don't have the exact numbers. But I can get them for you.

Senator NICKLES. You might have the association provide that because I think that's of interest, too. I think, recalling Mr. Bush's statement, he was talking about how there was a greater decline in gas activity today, even in relationship to oil activity.

Mr. POTTS. Absolutely.

Senator NICKLES. The total number of rigs is down over half, and if there's a greater decline in gas, then I think that the problems in the future, as far as adding reserves and so on, would even be more substantial in gas.

Do you think Mr. Lawrence, when he was talking about gas reserves, though being increased, or proven reserves, that maybe that was a direct result of the fact that you did have extremely high prices for the deep gas and some very large reserves were found in deep gas, although now that those prices have declined, the reserves are there, but no activity or not as much activity as, say, there was a couple of years ago?

Mr. POTTS. Yes, I think that is probably absolutely true.

As a matter of fact, I thought Mr. Lawrence maybe was talking about Saudi Arabia or somewhere like that. When I heard his figures, it was mind boggling to hear those particular points.

One point that I would like to address to a statement of Mr. Balis, if I may, is about the profits from producing wells that are paid out. I think he's referring to 104.

I think it's important that it be said that we, who drill wildcats, where do we get this money? We get this money from our producing wells. It's a site that's soon lost. If we didn't have to drill any more wells, this would obviously be true. But when independents—we reinvest 108 percent of our cash flow every year. Now, we do this by borrowing money from the banks and from outside sources. We don't stick it in our pockets. We don't buy Sears or Montgomery Wards, as perhaps some companies have. But we reinvest this in looking for the 90 percent of the wildcat wells that the independents drill.

So we need these profitable wells to be able to drill. These are the seeds from which we are able to find new production. It's very important that we have a profitable well once in a while to drill the dry holes that we drill. When we drill 50 wildcats and only 1 has significant recoveries, that's a bad success ratio.

Senator NICKLES. Mr. Balis and Dr. Cooper, you both indicated in your statements, I think, one, opposition to any change—or Dr. Cooper, you didn't mention this, but, Mr. Balis, you did—any change in regard to old gas prices, whether it be as minimal an effort as just touching those prices as they're renegotiated, which would be a voluntary between two parties, and/or as those contracts terminated, then they would not be subject to decontrol, at least under the proposal. But you mentioned your opposition to even that amount of deregulation of old gas?

Mr. BALIS. That's correct.

Our view is that, first of all, it's a really fortuitous event when those contracts end in the context of the regulatory scheme under which they were entered into. In other words, at the time that these natural gas contracts for 104 and 106 gas were entered into, they were subject to the Natural Gas Act. There was no NGPA. The gas could not be abandoned without abandonment authorization from the then-Federal Power Commission.

The rates were set on the basis of area and national rates, and that was the understanding of all the parties when the contracts were entered into, that that gas was going to go to that particular purchaser forever at the prices that were set by the Federal Power Commission forever.

Senator NICKLES. Let me ask you a question.

Some of those contracts were written prior to 1954. They were written prior to Federal regulation.

Do you think maybe those should be allowed?

Mr. BALIS. I would expect that most of those contracts already expired.

Senator NICKLES. Some of them were life for lease and still producing.

Mr. BALIS. Still, whether or not those contracts were written prior to 1954, they have been covered all of this time by the Natural Gas Act's rate setting, and what has been allowed under the NGPA already are increases above the cost-based rates that were set.

Senator NICKLES. Let me ask you another question.

Some of those contracts stipulated, that were, say, produced or the contracts written after, or let's say in the 1960s, they were written that they would be decontrolled when and if Congress decontrolled them. They would be subject to a negotiated price outside of any price schedule. Would you disagree with having those be deregulated?

Mr. Balis. Well, those contracts have already been interpreted so easily in favor of the producers, where they had clauses that said that the prices would increase whenever the Federal Power Commission in an area rate proceeding increased those prices after its evidentiary proceedings, they would get a higher price. That's already been interpreted to say that if a rate were set by Congress in the NGPA, the 102 or 103 or even 107 prices can apply to it.

So, already, the language in the contracts has been totally taken by the Commission and the courts to give the broadest possible reading to price increases for producers beyond what was intended when they were written.

There is certainly no more reason to have additional volumes of natural gas that are subject to price controls become decontrolled.

Senator Nickles. So, you would basically be in favor of no adjustment whatsoever, and if those gas contracts were written whenever, if they happened to be stipuled under 104, they should be forever and ever regulated?

Mr. Balis. That's correct.

Senator Nickles. Let me ask you one additional question. There are some other committee members here, and I'm sure they want to ask questions as well.

We are buying gas from Mexico and Canada. We're importing gas from other countries, LNG and others. I'm asuming that that gas is just as old as the gas that's in the United States.

Does it really make a lot of economic sense for us to pay Canadians $3.30 or more for that gas that we're paying domestic producers 50 cents for?

Mr. Balis. Absolutely not.

In fact, one of the things that's wrong with what's going on is we should not be paying the higher prices to Canada.

Is that what you're asking me? That's my response. Absolutely not.

We shouldn't be paying the higher prices to people in other countries above what the economic value of the gas is. And, in fact, the various pipelines—and this is something that ought to be looked into here hopefully, as well as at the FERC—are now filing at the FERC to create two-part rates in their purchases from producers in Canada. In other words, where before the entire cost of purchased gas was included in the commodity rate of the pipeline, there is now an artificial distinction being created where part of those costs of purchased gas are being moved over to a demand charge that's going to be paid by the U.S. interstate pipeline, whether or not the gas is taken, so that the commodity rate will look cheaper on the Canadian gas that's being imported, and they can say they're following the least cost strategy by purchasing that gas, rather than gas produced in the United States whose total cost is cheaper than the Canadian gas. It's something that has been filed for by Transco and is going through a hearing already. Texas Eastern just filed for it. I think Northwest Pipeline has filed to do it. It is something that we have opposed, that is, various municipal systems have opposed, at the FERC, and so have a number of large distributor systems as well.

We think that it is inappropriate, certainly inappropriate, to make imported natural gas artificially marketable by creating two-part rates for its importation in the United States.

Senator NICKLES. Mr. Balis—Dr. Cooper, I'm not sure if you addressed this—but, Mr. Balis, you came out very strong against FERC's proposed rulemaking as it pertained to gas carriage. Also, I think you made a strong statement against any type of contract carriage. Is that correct?

Mr. BALIS. That's correct.

Senator NICKLES. Any problem with bypassing the LDC's?

Mr. BALIS. To the extent that there is any contract carriage that's allowed, it should be limited to purchases that are made in the field by distributors as opposed to end users.

Senator NICKLES. So no contract carriage for an end user?

Mr. BALIS. That's correct.

Senator NICKLES. That would basically nullify whatever this committee or Senator Bradley and others have been trying to come up with. If there was contract carriage, you're saying it would only apply to distribution companies and not directly to the end users?

Mr. BALIS. We have a tremendous fear, from what we've already seen, from SMP programs, et cetera, blanket certificate proceedings, that what happens is we have a result of a bifurcated market, where the industrial end user, with great economic power, with large use, with high load factor use, is able to go in the field, make a good deal for itself, purchase the large amount of gas, and, meanwhile, the residential and small commercial consumer who is sitting behind the distributor, who does not have that economic power and who is locked in to the particular system, is stuck paying the higher prices that exist under today's pricing scheme, and would continue to be stuck with those higher prices because they would not have any economic way of getting its price reduced.

This will only make it worse.

Senator NICKLES. Well, could it be that maybe the LDC's weren't very astute in their purchasing practices?

Mr. BALIS. Well, the LDC's didn't have much choice in their purchasing practices since they have their interstate pipelines that support them.

Senator NICKLES. Let me just ask you one final question.

Mr. Atwood has already commented on the act that he had some plants that actually had to shut down until basically they ended up doing somewhat of a bypass or direct purchase type of agreement. I know of some cases of some plants in Arkansas where there is the exact same situation, where those plants shut down. They weren't competitive. They came up with basically almost a direct purchase, or a contract carriage type situation, and those plants were able to continue.

Are you opposed to that type of thing?

Mr. BALIS. I think the question is whether or not they were being served by distribution company systems and how long a period of time they have not been.

In other words, if they were shut down from the mid-1970's to the mid-1980's, customers are not being counted any more in the historic customer loads of the distribution system. It may have to be something that could be worked out, and certainly that's something the FERC can work out on a case-by-case basis, as opposed to legislation. Legislation has a way of becoming very broad, and including a lot more people than the most acute example that's brought up at a committee hearing, and a lot of other people start to fall in there who are historically served by distribution systems or, at least, through a distribution system.

In other words, we have different levels of our opposition to contract carriage. We're opposed to it outright. If it exists, it ought to be limited to distributors. Even if end-users are able to participate in it, they should still not be permitted to simply bypass a distributor for transportation and hook up their line directly to the interstate pipeline which then even causes the fixed costs that they picked up to have to be born by the residential consumers.

Senator NICKLES. Hearing your argument brings back not so fond memories of a couple of years ago, when we worked for over a month on Bradley's contract carriage, and you were more successful than I would have cared for and made that entire—if I remember, the LDC's almost had a veto on the availability of contract carriage, which made something that some of us thought might work. It looked to me like it almost wasn't workable, and that's one of the reasons why I've avoided contract carriage in the bill that I've introduced today and that I've mentioned before. This is because it may look very good to a lot of people, but if you get as involved as it can be, it may not be the solution many people are looking for.

I want to pass on to other committee members who have been very patiently waiting that we will have a vote at 12 o'clock.

Senator Ford, did you have any questions?

Senator FORD. Yes, I do. I have a few questions that I would like to get in before 12, but I will yield to Senator Rockefeller.

Senator NICKLES. All right.

Senator ROCKEFELLER. Thank you, Chairman Nickles. I appreciate the chance to ask a question.

There was not a great deal of discussion this morning in this sort of barrage of Oklahoma good will here of stripper wells in the State of West Virginia.

Mr. Potts, I suppose I would need to look at you as somebody who might address that. You did not, either in your testimony or in your comments. But I assume you know that West Virginia has a lot of those wells, many thousands of those, and that about 90 to 95 percent of all that we do, and we are, I'd say, probably among the top two or three producers east of the Mississippi in terms of natural gas, and, therefore, the future of stripper wells and in which block are they put, so to speak, is obviously important to us.

In your judgment, if they are put in this second block, is that something that FERC should be able to do by itself, or is that something that should be done only by legislative amendment to the act?

Mr. POTTS. The stripper wells, of course, are very important to this Nation because so much of our production is declining, and the lack of including stripper wells in block 1 I think is an oversight on FERC's part. If they're going to proceed in this block 1 and block 2, and stripper wells are included in block 2, you will see a great number of wells plugged out because the price, the market price, is less than what the stripper well price may be on certain occasions.

My recommendation would be that stripper wells, if FERC proceeds forward, be included in block 1, and allow the average price of block 1 come up to accommodate the stripper wells.

Senator ROCKEFELLER. I appreciate that recommendation, but in your judgment, does FERC have the authority to lay out this type of block 1, block 2 allocation, except as it is ratified in amendment by the Congress to the act?

Mr. POTTS. I really am not qualified to speak to whether they do or don't have the authority, Senator.

Senator ROCKEFELLER. In that you represent our folks, too, would you be willing, in the questioning period—not today, but in the next couple of weeks—answer that question for me?

Mr. POTTS. Yes, I'd be happy to.

Senator ROCKEFELLER. I assume that would be another legal opinion which your folks would be willing to do.

Mr. POTTS. Right.

That's exactly what it is.

Senator ROCKEFELLER. Now, you indicated that we have some 6,000 people who are employed directly in this area, and if what you suggest is correct—and I believe it is, and that is that putting stripper wells in block 2 would cause wells to be shut-in—that would clearly, then, have a very bad effect on a State which is known for coal, but which has a great deal of oil drilling and natural gas drilling. That's a substantial industry in our State, and one in which we take some pride.

Would there be any combination of circumstances which could cause those wells, once closed, to be opened? Or would you assume if they were block 2, so to speak, that they would simply remain closed, and the industry would shut down?

Mr. POTTS. In my judgment, sir, if those wells are plugged and abandoned because of whatever reason, price deterioration in this particular case, you could not economically redrill any of those wells, and that production would be lost forever.

It is extremely vital in this diminishing supply of energy that we have in this nation that we somehow attempt to allow all of our energy that can be produced to be produced and not prematurely abandon a small quantity of gas that will, in the long run, add to the overall needs of this nation.

So, we must preserve all stripper wells as long as we possibly can because, once they are plugged, no one will redrill for that small quantity of gas left in those rock ports.

Senator ROCKEFELLER. If I might ask one more question, Mr. Chairman—it's about 10 of—to Dr. Cooper, sir, you run a delicate line, I would think, because I know you care about employment and jobs, and you also care about the cost of the product—are you a lawyer?

Dr. COOPER. No, I'm not.

Senator ROCKEFELLER. Would you like to be for a moment?

[General laughter.]

Dr. COOPER. If I don't know the answer, I won't want to be, but if I do, I'll play lawyer.

[General laughter.]

Senator FORD. Go blame it on the lawyers.

[General laughter.]

Senator ROCKEFELLER. Do you have any instinct, or how do you balance in your own mind this business between—I mean, it can be said, I suppose, as these things are blocked in two different areas, you know, that a cheaper price on the one hand causes 6,000 people to go out of work in West Virginia and an industry to shut down in one State which already has ample unemployment already; and, on the other hand, I suppose you could argue, as indeed you might, that all that matters in the long run is the lowest possible cost. How do you balance these things in your own thinking?

Dr. COOPER. Well, I think both the NGPA and, in some senses, the FERC—and here I may be a little nicer to FERC than I was before—NGPA looked for a series of categories of gas. In essence, they were trying to find the supply curve. Old gas was there and it was cheap, and so we didn't give it a price, we captured those rents.

Economic theory tells us that a two-part tariff makes sense. FERC has said because of a decision on old gas that a three part tariff makes sense. That's essentially what they proposed.

The balance here is between the first block, which is not to lose those rents on old gas, and the second block, which is to leave the incentives for new gas out there.

You have proposed a specific category—and I will agree, if the price of that gas is much above the block 2 average, you're not going to be able to produce it.

I think Congress' intent in balancing the equities in the NGPA was to reserve those rents.

What you're suggesting is that Congress—and, obviously, other members have suggested—go back and revisit the distribution of rents. Because, in essence, by allowing the price of stripper wells to move above, to be included in block 1, move above the market clearing price, what you're doing is funneling the rents from the old gas consumers to the stripper well producers.

You put the question exactly. That's a political judgment, balancing the equities and the efficiencies.

There is a little bit of difference between my perspective in my prepared testimony and in my statement. I'm willing to consider the efficiency, the costs of some decisions. I think, if one could make a very strong case that there are extremely large quantities of gas to be had by dissipating some of the rents of old gas, you would have a stronger argument.

Again, it's a political choice. It's a balancing between the equities and the efficiencies.

Obviously, there are regional equities, a state of impact versus the average as spread across the Nation.

Senator ROCKEFELLER. Would it be your judgment that Congress would have to make a specific amendment to the act in order for there to be blocking categories, such as FERC is proposing?

Dr. COOPER. Well, again, here I'm going to say I'm not a lawyer. But, in fact, it's my judgment that the legislative justification for block 1 is overwhelmingly clear in the NGPA. I think the intent of NGPA was clearly to save those rents of old gas and pass them through to firm end use customers.

Whether or not it can do block 2 and block 3 is a different question. I have not looked at that in one sense, in my central concern.

But clearly the notion that honestly you might end up with new and old stripper categories—you could argue that NGPA identified stripper and gave it a higher price, and the blocking system is denying it the higher price that it was to be allowed. I mean, at that point I'm glad I'm not a lawyer.

Senator ROCKEFELLER. Thank you.

Thank you, Mr. Chairman.

Senator NICKLES. Thank you, Senator Rockefeller.

Senator Ford, did you have any further questions?

Senator FORD. Yes.

I wanted to yield to Senator Rockefeller because I had to leave.

There is a fear of mine, and I'm not sure that it's agreed with by my colleagues, but we are getting into energy problems, and we're facing those in the future. Maybe I ought to let natural gas go down the drain and let it enhance the use of coal because we're the largest coal producer in the country. But I think we need all of the energy sources to keep us in balance.

I find, Mr. Chairman, before this committee and the testimony that we've heard, that refineries are going down. They're closing as it relates to gasoline; that companies are now raiding those refineries for parts, to put them into other refineries, and they'll never come back on line.

We find a typical operation that, when there are no gasoline lines and nothing like that, there's really no worry about energy supply.

We find other countries trying to figure out a way. Mexico just dropped their oil prices. And we find OPEC trying to figure out a way to stop some of their countries from cheating and selling it cheaper, as Saudi Arabia begins to crank up their refinery and put gasoline on our shores much cheaper than our refineries can produce it.

We begin to feel lots of problems.

The problem, as I see it, is the economy and how we are going to turn that around. Maybe it's mostly smokestack that we have problems with, and we're going to services, and maybe the energy needs in the future will not be as great as we have seen in the past because we are having new technology come on board. Yet, we're trying to close down any synfuels operations, which is across the board.

Mr. Potts, you say that the decline in drilling is 60 percent. Well, if you don't have the sales, there's not much desire to drill, is there?

Mr. POTTS. That's correct.

Senator FORD. No. 2, if you don't have the sales, you are out looking for other sales, for other ways to use that product in order to enhance the sale, in order to have more drilling to make more profit and that sort of thing.

Where do you make the profit if you invest 108 percent? Is that just of cash flow?

Mr. POTTS. Yes.

Senator FORD. Well, what is the profit with the cash flow?

Mr. POTTS. Well, essentially, what we're saying is that if my income is, say——

Senator FORD. A hundred thousand dollars and you put $108,000 back in.

Mr. POTTS [continuing]. $100,000 and I'm going to spend $108,000, but that will be made up in a stream or a flow from my production; it will be made up from investors that I go to participate in prospects that I might drill; it will also be made up in interest that I get from the bank, that I borrow.

So I spend more each year than my income. It's not net profit per se. It's my cash flow that I'm referring to.

Senator FORD. Well, that's just like losing money on every deal, and you depend on volume to get by, isn't that it?

Mr. POTTS. That's right.

Senator FORD. Well, I've heard that before as you go broke.

It looks like if you hit 1 out of 50, that your prospects are not too good.

I don't understand all of this, and maybe I'm not supposed to, and that's the reason I make some bad judgments on this committee. But, as it relates to the contract carriage, I think the chairman understands very well that this committee did not approve that, and, if I have anything to say about it, is not going to.

But, nevertheless, some of the things that we're talking about bother me because of the whole energy pool. Until we have a sale for it, until we get our country in an economic posture, then we're going to be seeing other countries that can produce it lower than we can over here.

It's a free market in this country; it's not a fair market.

Let's talk about domestic supply for a minute.

One of the things that you talked about, Mr. Potts, was the importance of the stripper wells.

As I understand it, that's a significant part of the domestic supply, about 10 percent.

Am I correct in that figure?

Mr. POTTS. I heard not quite that high. But 7 to 10 percent, in that range, yes, sir.

Senator FORD. Well, if you're for it, you go to the high side; if you're against it, you go to the low side, I've noticed.

How about 8.5?

Mr. POTTS. That's fine.

Senator FORD. OK, 8.5.

So, what Senator Rockefeller's talking about is a significant portion of our domestic supply.

Mr. POTTS. Yes, sir. It's a contribution.

May I expand on one of your comments about this cycle that we have, although we have a surplus today?

Senator FORD. Yes, sir.

Mr. POTTS. And you're concerned about the energy for the future. You know, in 1978, when we had the lines, somebody said why didn't they warn us, the producers. Why didn't we warn the public about the fact that we were running out of natural gas, and we were running out of oil?

I think you have hit upon a very important point, sir, that it is in time to wake up and take notice—not when the lines form, because we can't turn up the spigot.

Senator FORD. That's reacting instead of acting.

Mr. Potts. That's right.

We can't cut out that timeframe.

It's a little bit like a young couple getting married. They want to have a baby right away. But there's nothing they can do to shorten that 9-month waiting period, as much as they want that child.

We've got the same problem on prospects.

Senator Ford. You just got my attention, Mr. Potts.

[General laughter.]

Mr. Potts. We have prospects. We can't drill those prospects. It's an average, roughly, of 3 years from the time of the conception of a prospect until that prospect is on production. And, as much as we're in a hurry to get that production to the consumer, we can't do so. It's in everybody's interest in this room that I, as a producer, stay healthy and in the business, that I don't leave and go into the construction business, or something else, because we have trained people and it takes time to come back and marshall the forces.

This group has a tremendous responsibility for making this Nation aware of our energy problems, cyclic as they may be, and although we're in a surplus now, that is coming to an end in the not too distant future. And that gas bubble will disappear. When it happens, it will be instant.

Senator Ford. Another thing that bothers me, too, is that industry is beginning to whip on other portions of the total distribution system. We should not, in my opinion, make any of the industry the whipping boy. We need to cooperate.

Mr. Potts. We need everybody.

Senator Ford. Yes, we need everybody. We don't need to take out our frustrations on one item or one entity.

We're going to have to go and vote in a minute, but I'd like to stay with you a little while longer, but, I guess, maybe, I'd better not.

Mr. Atwood, on page 8 of your statement, you said,

> As a result, new arrangements, based upon gas transportation, have been utilized to acquire natural gas at costs lower than otherwise possible with traditional marketing of natural gas by pipelines, hence to keep nitrogen plants operating and to reopen closed facilities.

You mention these new arrangements and so forth, but you never outline what your arrangements are.

Could you do that for me very briefly, please, sir?

Mr. Atwood. Yes, sir, I certainly could.

At our Fort Dodge, IA, plant, it had been shut down. It's served by Northern Natural, through People's through Northern.

The plant had been shut down for something over 30 months of time. Their market value of gas was such that we just couldn't compete. We were something more than a dollar out of the market. That's right in the Corn Belt, where nitrogen is needed. We were importing it, bringing it into the State of Iowa by renegotiating, by buying gas in Oklahoma; and by arranging a transportation agreement with Northern Natural, we were able to put gas into the plant some 70 cents cheaper than we had been doing it. That let the plant come back into an operation at a break-even level. And we did so.

Senator Ford. Well, what I find, then, in your statement, is that you have, through free will, here—you know, you had a willing seller and a willing buyer, and you were able to negotiate without the Federal Government telling the pipeline they have to carry it, or somebody says they have to put it in the pipeline and sell it to you. You were able to go out into the market and to make an arrangement with the producer, or gas that you own, that sort of thing, and to contract for that to be transported to you at a lower price.

That was out there negotiating in the free market, wasn't it?

Mr. Atwood. Well, in a way it was, and in a way it wasn't.

Senator Ford. You sound like an economist—on one hand it is and on one hand it isn't.

Mr. Atwood. The plant, you have to remember, was shut down for something like months of time. The gas company, the gas pipeline, the local distributor were earning nothing during that period of time. I couldn't get their attention that we were losing and we were not going to be able to sustain that operation, that we were going to have to lay off people.

We finally did those things.

But it wasn't until they voluntarily, through some action, agreed to transport the gas. But if they had maintained the position that they had held for 30 months, the plant would still be down.

So, yes, it was the free market working. But it was where everybody began to hurt. I wasn't able to get their attention till I stopped paying the bills.

Senator Ford. Well, the economic factor brought everybody together.

Mr. Atwood. Certainly.

Senator Ford. I find too much of a push and too much leaning on everybody else to try to protect everybody's little bailiwick or shore up their own back here—why, they begin to hurt and the opportunity presented itself and it worked itself out, even though you had 30 months of tough time and inability to convince the entity that you needed to open up.

Mr. Atwood. But without relaxation of some of the rules regarding transportation, we would not have been able to accomplish that, even if the free market decisions had been right.

Senator Ford. Let me ask you this question.

If the pipeline that is now bringing gas to you at 70 cents lower—I guess that's 70 cents per mcf?

Mr. Atwood. Yes.

Senator Ford. What if they were full and they already had contracts, long-term contracts, to you, maybe? There's not a thing they could do about that if their pipeline's full.

Mr. Atwood. No. But in this particular case, their pipeline—we're utilizing the same facilities that we always have.

Senator Ford. Oh, I understand that.

I just said if it were full, you'd still be out, then, under those circumstances, wouldn't you?

Mr. Atwood. Yes.

Senator Ford. Do you think we ought to impose ourselves on that pipeline to say hey, here's an entity that needs some gas and they want to do it this way, and you're required to ship it?

Mr. Atwood. Well, there are some blanket arrangements there. In this particular case, since we were a long-time customer and we were paying a usual contract demand for that, we had space already arranged.

Senator FORD. I understand that. But I'm just saying if you wanted to move in—what I'm fearful of is we're going to say to business out there, which in this particular case happens to be a pipeline, we're saying to them look, you've got to carry X regardless, and then they've got to look at one of their regular customers who's been there for a year, got a long-term contract, and there's going to be disruption, even though the supply is there.

What I'm fearful of, if we get into this contract carriage provision, is that you're going to force some pipelines to have to shift or make other arrangements. You're going to make the end user do some other things.

I'm fearful of us getting into your business too far.

Mr. ATWOOD. Well, that could occur. But, as usual, the customer who is taking the final delivery is taking it through the system that he's taken delivery under for the long period of time. It's only a different way of arranging for the transportation.

So, I doubt seriously that you're really going to cause any burdensome using up of existing capacity.

That's really the problem, that you're hooked to a specific end user, to a specific pipeline distribution part. Most of the transportation arrangements that we're talking about don't really interrupt the physical system that's there.

Senator FORD. Well, I'm not talking about interrupting the physical system. I'm talking about interrupting, I don't want us to interrupt the contract that you have with me, and how does it get to you? We say to that fellow, look, you've got to divert some of that over to Y instead of sending it on directly to A.

Mr. ATWOOD. Well, contract interruption is a different thing than pipeline capacity.

Senator FORD. But pipeline capacity is all you can do, isn't it?

Mr. ATWOOD. But the point is that an end user in Fort Dodge, IA—you see, under this particular arrangement and all the other transportation arrangements that we've been able to negotiate within the State of Oklahoma, we haven't used any different physical system.

Senator FORD. Well, that's intrastate rather than interstate, isn't it?

Mr. ATWOOD. Well, Fort Dodge, IA, is not. That is an interstate system.

Senator FORD. But you refer to Oklahoma when it's appropriate and to Fort Dodge when that's appropriate.

Mr. ATWOOD. I'm just saying that these are some of the transportation arrangements that my company was able to enact, and they didn't involve any different physical systems.

Senator FORD. Well, what I see here, Mr. Chairman, is something I want to be very careful about. Maybe I'm not being as clear as I ought to be. But I'm just very concerned that we stay out of your business as much as possible, that we be helpful, and that in being helpful that we don't create additional costs, that we don't create inability to carry out a contract—several of those items.

You might go ahead and tell me what you heard over there?

Mr. ATWOOD. I didn't hear him.

Senator FORD. You didn't hear him?

[General laughter.]

Senator FORD. Well, maybe Dr. Cooper did.

You understand what I'm trying to get to. I want you to have the help I want you to have the gas. The problem I see here is the economy, and we're at about 80 percent, though we've been down below 70 in the last 2 or 3 years. We're not up to the 95 or 98 percent.

Mr. ATWOOD. Let me speak to the smokestack industry that you're talking about.

These are the manufacturing jobs that you have to save, and the only way you can save them is economically.

Senator FORD. Right.

Mr. ATWOOD. The way you do that is make the best business deal you can.

Yes, I don't want you negotiating my contract——

Senator FORD. That's right.

Mr. ATWOOD [continuing]. But I don't want you to keep me from doing it, either.

Senator FORD. That's right. I don't want to, either. But I want to be very careful that we don't put somebody else in a vulnerable position.

Mr. ATWOOD. I understand that.

I don't think we've ever been an advocate of taking an unfair advantage in any of these issues. It's always been a straight economic—if the industry needs to be saved, it'll be saved, if it's economic to save it.

I personally feel that the fertilizer industry, the domestic fertilizer industry, needs to exist in this country, or we're going to lose the low-cost food.

Senator FORD. Well, what if you made a judgment about cost, and you went out and bought a bunch of gas, and, all of a sudden, the Congress says at the end of the contract period that you renegotiate? All right—or that we deregulate and let it go up as high as it possibly can. Then the individual who went out and took a chance and has a lot of low-cost gas is able to deliver it to you somewhat cheaper and he gets the business.

But we're saying renegotiate at the end of that contract or deregulate old gas, and I'm beginning to wonder if a fellow makes a good judgment and another fellow makes a bad judgment, we're going to take the side of that fellow who made a bad judgment. I don't particularly think that's good.

If you go out, in order to make nitrogen, or whatever, and you buy low-cost gas and have a long-term contract, for the life of the lease, and we turn around and say the lease is 20 years old, you're getting ready to renegotiate it, so you can renegotiate any price—well, that's deregulating the old gas that is now, by law, regulated for its lifetime.

So, we're saying to the fellow who made the judgment for that gas, and you made the contract with him, you're out.

I don't particularly think Government is out to do that because they made a judgment that was wise. Others didn't get the low-cost gas. Therefore, they are now trying to get into the posture to get into competition, to have your costs accelerated.

We got into that in Louisiana. Sure there is low-cost gas going to, I believe, this chemical operation, and we were sitting here trying to increase that. I think it involved Texaco, as I recall.

So, we were getting ready to increase that cost, which was going to close that plant down. They had a long-term contract. You know, the big fellows up here who know it all were getting ready to put a plant out of business down there.

That's what I'm trying to prevent here. That's what I think we maybe are easing toward as we begin to take care of those, and see where they can make more money when their costs have already been reimbursed over the long period of time, and are still making good money. They were making awful good money at the time they made the contract.

Well, I want to be very careful about it.

Thank you for your time, Mr. Chairman.

Senator NICKLES. Senator Ford, we appreciate your participation, as always.

You've always had a strong interest in this legislation.

Senator FORD. We're a consuming State, Mr. Chairman, and we have to be very careful that our consumers are not damaged.

Senator NICKLES. I understand.

To all of our panelists, I appreciate your participation. I think the meeting this morning was quite helpful, and I look forward, too, to the submission of additional comments, if you have them, particularly concerning the notice of proposed rulemaking.

We'll keep the record open for 30 days for committee members to submit questions and to get your responses, and also to receive your additional comments concerning the NOPR.

Thank you very much.

The committee is adjourned.

[Whereupon, at 12:13 p.m., the hearing was adjourned.]

APPENDIXES

Appendix I

Responses to Additional Questions

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

July 19, 1985

Honorable Don Nickles
Chairman, Subcommittee on Energy
Regulation and Conservation
Committee on Energy and
Natural Resources
United States Senate
Washington, D. C. 20510

Dear Mr. Chairman:

Enclosed are my responses to Senator Jeff Bingaman's questions and Senator John D. Rockefeller IV's questions for the record in the June 18, 1985, Subcommittee on Energy Regulation and Conservation hearing on natural gas issues.

As discussed with the Committee staff, the questions submitted by several pipeline companies regarding the Commission's Notice of Proposed Rulemaking and transmitted to the Commission staff by Senator Johnston will be treated as comments on the record and will be considered in the rulemaking proceeding itself.

If I may answer any further questions or provide you with additional information. please do not hesitate to contact me.

Sincerely,

Raymond J. O'Connor
Chairman

Enclosures

cc: Honorable Howard M. Metzenbaum
Ranking Minority Member

SENATOR JEFF BINGAMAN'S QUESTIONS

Q1. With respect to the Notice of Proposed Rulemaking, issued in Docket No. RM85-1-000 (NOPR), the Commission is proposing to amend its transportation program by requiring any pipeline which voluntarily chooses to engage in self-implementing transportation services to provide such transportation service to all customers on a non-discriminatory basis.

a. Is the Commission proposing to in effect make pipelines engaging in self-implemented transportation common carriers? In other words, if demand for transportation service exceeds available capacity, is the Commission proposing to require the transporter to pro-rate its capacity among those requesting transportation service?

A. No. The NOPR would not make pipelines common carriers. Participation by the pipelines would be voluntary, depending upon whether or not individual pipelines wish to participate in blanket-type programs involving transportation. Capacity would be available on a first come-first served basis.

Q1b. If the Commission is requiring the prorationing of capacity, how would such a system work under the NOPR?

A. The Notice of Proposed Rulemaking does not require prorationing of capacity. Rather, it is contemplated that capacity would be made available for transportation on a first come-first served basis.

Q1c. Would common carrier status affect the ability of pipelines to adequately serve its sales customers?

A. Because the NOPR does not propose common carrier status for interstate natural gas pipelines, the Commission has not explored the possible results of so doing.

Q1d. It appears that the non-discrimination requirement applies to local distribution companies and intrastate pipelines engaging in transportation under the Commission's Order No. 63 program and NGPA § 311. Is the Commission proposing to also require such intrastate entities to become common carriers.

(i) If so, would such common carrier obligations extend to requests for purely intrastate transportation service? Would the imposition of such common carrier obligation by the Commission infringe on areas tranditionally left to State regulation? For example, who would decide how the LDCs or intrastate pipeline should pro-rate existing capacity among the transportation customers?

(ii) Did the Commission intend to apply the non-discrimination requirements to existing transportation services by intrastate pipelines and LDCs which are on-going at the time any Final Rule is issued in this proceeding?

A. As indicated above, the Notice of Proposed Rulemaking does not impose common carrier requirements on pipelines.

However, the NOPR would impose nondiscriminatory access conditions on those interstate transportation transactions performed by intrastate pipelines under blanket-type authority issued under both the NGA and the NGPA. Whether or not the Commission imposes such conditions upon on-going transactions will be determined at the time any final rule is issued.

Q2. In the NOPR, the Commission also proposes to require interstate pipelines to segregate its purchased gas costs from both producers and pipelines into 3 separate blocks:

Block I - All "gas costs" attributable to purchasers of relatively low cost "old gas," or gas which qualifies as NGPA Sections 104, 106(a) or 109 gas;

Block II - Gas costs of the other relatively higher priced NGPA categories of gas and "all comparable costs of imported gas at the border or at the tailgate of the regasification plant;

Block III - All demand and commodity costs not included in Blocks 1 or 2.

All gas costs included in Block I are proposed to be allocated to the pipeline's existing customers, and the gas costs in Block II are allocated to meet any remaining needs of existing customers and to new customers.

a. What did the Commission intend by "gas costs"? Does this include such "add-ons" as gathering. compression, treating? Would such costs be treated as "gas costs" if performed by the pipeline instead of the producer?

A. The term "gas purchase costs" is defined by the Commission's existing regulations in 18 CFR § 154.38(d)(4)(n.1). These costs generally include those costs directly associated with the purchase of the energy units in the gas stream, including those costs that are recoverable under Section 110 of the NGPA as allowed under the Commission's Order No. 94-A, issued January 24, 1983 (22 FERC ¶ 61,055). The treatment of costs associated with facilities constructed by pipelines to perform production-related activities is currently addressed by the Commission on a case-by-case basis. The NOPR does not specifically address the treatment of such costs.

Q2b. With respect to imported gas, what does the Commission mean by the term "comparable cost".

A. The terms "comparable cost" refer to those associated with the purchase of the energy units as described in the answer to Question 2(a).

Q2c. Has the Commission done any in-house studies of the dollar impact this proposal will have on existing and future customers? If not, can the FERC conduct a study estimating what the cost impact would be?

A. The Commission has not made a study of the potential dollar impact of the NOPR. Comments were due by July 15, 1985, and a public conference is scheduled for August 1, 1985.

Q2d. What impact will those proposals have on the pipelines' take-or-pay liabilities?

A. Under this proposal, those pipelines willing to provide nondiscriminatory transporation would be able to buy out problem contracts with high take-or-pay obligations and indefinite price escalator clauses. There would be a rebuttable presumption of prudence if the buyouts met certain criteria. To the extent that pipelines are able to take advantage of the "safe harbor" presumption as proposed in the Notice of Proposed Rulemaking, the proposal should tend to allow pipelines to reduce their take-or-pay obligations.

Q2e. Does the Commission's proposal have any bearing on issues of rate design (i.e. the amount of a pipeline's fixed cost which are recovered through fixed monthly demand charges)?

A. The proposal would not change the methodology that is currently being used to classify and allocate costs and to design sales rates on individual pipelines. However, to the extent that customers convert from sales service to transportation service, there could be some impact upon rate levels, including sales demand charges.

Q2f. Do you intend to address generically rate design issues in future proceeding such as the issuance of another Notice of Proposed Rulemaking or a Statement of Policy? If so, when?

A. The changes embodied in the present NOPR may significantly affect all segments of the natural gas industry. We will determine after some experience has been gained whether other changes are needed, including changes in sales ratemaking.

SENATOR JOHN D. ROCKEFELLER IV'S QUESTIONS

Q1. Mr. O'Connor, in your written testimony you have mentioned the Order No. 234-B program. Also, in your oral testimony you have said that the Commission has just acted to extend the program on an interim basis. As you know, this is a very important program for the Weirton Steel Corporation in my state. Since the Commission is under Court order to modify the program, I would like to know what steps the Commission and FERC staff will be taking to devise a new industrial program that complies with the court order and makes a smooth transition from the program you have just moved to extend on an interim basis?

A. The Notice of Proposed Rulemaking appears to comply with the court order vacating the Order No. 234-B program and is intended to make a smooth transition to a system of simplified transportation available on a non-discriminatory basis.

Q2. In reviewing your proposed rulemaking issued May 30th, I am interested in the analysis and rationale that went into the designation of stripper well gas, section 108 gas, in the block two category. It is my understanding that in the Natural Gas Policy Act (NGPA), Congress provided that section 108 gas would be forever regulated, thus providing an incentive to production of gas that would otherwise be left idle or shut-in. By putting the stripper or section 108 gas in the block two category, it would appear that the effect is to create a serious disincentive to production of this gas. Would you please comment on the Commission's rationale and cite the specific authority you have used to exercise this change?

A. The entire thrust of the NGPA is that gas prices at the wellhead be regulated through competitive forces subject to ceiling prices that remain on some supplies of gas. In putting section 108 gas in Block II, this gas would be subject to the same competitive forces as all other gas for which Congress established ceiling prices at an incentive level.

Q3. Also pertaining to the inclusion of stripper or section 108 gas in the block two category, what did the Commission calculate would be the impact on the consumer if this gas were included in the block one category?

A. The Commission expects that gas will be priced more competitively under a final rule issued pursuant to the Notice of Proposed Rulemaking than under current regulations. To the extent that gas can be produced at market clearing prices, it should be produced. On the other hand, if particular supplies of gas cannot be economically produced at market clearing prices, it is questionable whether it is either fair or even economically efficient for consumers to be required to pay such higher-than-market clearing prices.

Q4. In considering the development of the placement of the stripper gas category, did the Commission make an evaluation of how this rule would affect the gas industry in specific regions of the country, specifically in West Virginia or Appalachia?

A. The Commission's proposal is based largely upon the Congressional mandate of wellhead price decontrol provided in the NGPA. The billing procedure in the Notice of Proposed Rulemaking is intended to be consistent with the incentive wellhead pricing categories Congress established in the NGPA in determining how competitive forces could best be transmitted from the burner tip to the wellhead. Because Congress established no delineation between section 108 and any other pricing categories on a regional basis, neither does the NOPR.

FEDERAL ENERGY REGULATORY COMMISSION
WASHINGTON, D.C. 20426

June 27, 1985

Honorable Wendell H. Ford
United States Senate
Washington, D. C. 20510

Dear Senator Ford:

Enclosed are my responses to your questions for the record in the June 18, 1985, Subcommittee on Energy Regulation and Conservation hearing on natural gas issues.

If I can answer any further questions or provide you with additional information, please do not hesitate to contact me.

Sincerely,

Raymond J. O'Connor

Raymond J. O'Connor
Chairman

Enclosures

SENATOR FORD'S QUESTIONS

Q1. What is the Commission's target date for promulgation and implementation of the rule proposed in Docket No. RM85-1?

A. Our current timetable for the promulgation and implementation of the rule proposed in RM85-1 is Fall 1985.

Q2. How will transportation for low-priority and end-users be performed when the current regulations expire on June 30, 1985?

A. On June 17, 1985, the Commission issued Order No. 234-C temporarily extending the current regulations governing transportation for low priority end users until October 31, 1985, or the effective date of the final rule in RM85-1, whichever is earlier. The Commission sought a stay of the D.C. Circuit's mandate in Maryland People's Counsel v. Federal Energy Regulatory Commission, No. 84-1019, as necessary, to allow the extension to take place.

Q3. Why is the rule proposing to eliminate the rolled-in policy applicable to purchased gas costs?

A. The present practice of across-the-board rolled-in pricing permits and may encourage pipeline gas purchases at prices above market-clearing levels. Such purchases can then be balanced out by other low-cost gas which serves as a cushion. The proposed three-part scheme will not eliminate the possibility of that happening, but will mitigate the effects of pricing signals distorted by cushion gas, and will make explicit the effect of the cushion in the pricing of system supply.

The proposed three-part billing procedure would preserve the economic rents associated with this gas for the pipeline customers as Congress apparently intended. However, by confining the sales of old gas to the initial block, the effective use of old gas as a competitive tool in new markets will be blunted. Ownership of an old gas cushion will become less relevant for inter-pipeline as well as inter-fuel competition.

The proposed rule would, through the pricing of the second block, convey immediate price signals along the chain from distributor customers to pipelines to producers. Distributors would be able to base purchase decisions on the incremental cost of new gas supplies. Since customers would be purchasing from both blocks, a given pipeline customer's total gas costs would not necessarily change.

Q4. Why does Block 1 of the proposed purchased gas cost billing procedure exclude regulated natural gas classified under Section 102(d) of the NGPA?

A. Section 102(d) gas is proposed to be excluded from Block 1 because that gas is subject to an incentive price ceiling under the NGPA. The distinction between Block 1 and Block 2 gas is not whether it is regulated; rather, the distinction is whether the gas qualifies for one of the incentive-priced categories. The NGPA prescribed incentive prices to enable new natural gas to more nearly approximate its commodity value at the wellhead. On January 1, 1985, much of this gas was deregulated. While Section 102(d) gas has not been deregulated, its maximum lawful ceiling prices have been influenced by alternate fuel prices; the prices that can be collected should therefore continue to be affected by competition.

Q5. What incentive exists for natural gas producers to agree to only a percentage of take-or-pay amount due from pipeline purchasers?

A. The NOPR would provide the producers the opportunity for an immediate revenue stream as contrasted with the possibility of future take-or-pay revenues. In addition, producers have an incentive to avoid loss of markets while they are settling their claims with their pipeline customers. Finally, the Commission's proposed rulemaking would increase regulatory predictability concerning the Commission's review of the prudency of such settlements.

Q6. The proposed rule specifies that purchases of gas under sections 104, 106(a) and 109 of the NGPA will be included in Block 1. Suppose pipeline B purchases gas from pipeline A. Pipeline A's purchases include both old and new gas. Will pipeline B be required to separate pipeline A's purchases into Blocks 1 and 2, so that pipeline B's existing customers will have the benefit of pipeline A's old gas supplies?

6. Yes, it is contemplated that Block 1 gas will be treated consistently whether or not the purchaser is another interstate pipeline. Accordingly, Block 1 gas of the selling pipeline will be included in the Block 1 gas of the purchasing pipeline.

Q7. When existing customers switch from sales to transportation service, is there a corresponding reduction in the amount of Block 1 gas available to this customer?

A. The Commission expects to receive comments on the relationship between a customer's right to reduce contract demand under the NOPR, and the billing procedure for "Block 1" gas proposed by the NOPR. Under the NOPR, a customer's percentage entitlement to Block 1 gas would be based on its firm gas purchases for the years 1982, 1983, and 1984 as a percentage of the pipeline's total firm gas sales for those same years. The NOPR does not propose that this percentage entitlement be based on prospective changes in a customer's firm purchases due to exercise of its contract demand adjustment rights under Part 1 of the NOPR.

Q8. Does the Commission intend to modify the present abuse standard applicable to the passthrough of purchased gas costs?

A. In its Notice of Proposed Rulemaking, the Commission did not propose to modify the present standards in any way.

Q9. How does the proposed rule allocate capacity for nondiscriminatory transportation?

A. The proposed requirement that volumetric rates be designed to create incentives to use service in off-peak periods and disincentives to use service in peak periods lessens the possibility of capacity contraints. The proposal does not provide a specific formula for allocation of capacity for nondiscriminatory transportation. However, the proposed rule does request comments on whether firm sales customers should have the right to convert firm sales rights into an equivalent amount of firm peak transportation capacity.

Q10. Will the proposed rule create a disincentive for the continued exploration and development of new gas reserves?

A. The proposed rule, to the extent it would assure accurate price signals to both consumers and suppliers of natural gas, should provide incentives for the level of exploration and development of new gas reserves that is appropriate to the supply and demand conditions prevailing in gas markets over time. To the extent producers are able to perceive the opportunity for new markets, there should be an incentive to explore for and develop those reserves that are economical to produce under prevailing market conditions. This includes the development of reserves that can clear the market and still be economical to produce.

Q11. What curtailment scheme will apply to nondiscriminatory transportation? Will nondiscriminatory transportation customers be curtailed before firm sales customers?

A. Nordiscriminatory transportation would be subject to such curtailment plans as are on file with the Commission and included under the pipelines' effective tariffs.

Q12. Does the proposed rule provide producers an incentive to reduce current wellhead prices for natural gas?

A. The Notice of Proposed Rulemaking does not provide an incentive for any particular wellhead price of gas. The Notice of Proposed Rulemaking does provide for transmittal of more clear and accurate price signals between burner tip and wellhead. Under the circumstances of today, where there is a supply surplus and natural gas is experiencing difficulty competing in the marketplace, it is reasonable to assume that the price signals will convey the need to reduce some prices.

Q13. What is the definition of "volumetric rate" which the rule proposes to apply to nondiscriminatory transportation?

A. A volumetric rate is a rate charged on a per-unit basis of volumes transported or sold. It is a one-part rate; therefore, the overall cost changes in direct proportion to volumes transported or sold.

Q14. Does the proposed rule affect the current rate structure applicable to firm sales service provided by interstate pipelines?

A. No. It does not propose to modify the rate structures of individual pipelines as they apply to sales service. The rate structures and the methodologies used to develop individual rates will remain the same. However, the allocation of costs to the transportation service and any change from sales to transportation service may well affect sales rates.

NATURAL GAS SUPPLY ASSOCIATION

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Nicholas J. Bush
President

Mr. Howard Useem
Professional Staff Member
Energy Regulation and Conservation Subcommittee
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Re: Follow-up questions to witnesses appearing at July 11, 1985 Subcommittee hearing on the "Current State of and the Factors Affecting the Natural Gas Market"

Dear Howard:

Please find enclosed herewith NGSA's responses to the questions propounded to us by Senator Ford earlier this month. If you have any questions or require additional information, please do not hesitate to contact me at your convenience.

Thank you for your cooperation and assistance.

Sincerely,
Natural Gas Supply Association

By Nicholas J. Bush
Nicholas J. Bush
President

Enclosures

NJB:WJS:jt

RESPONSE TO QUESTIONS PROPOUNDED BY SENATOR FORD TO MR. NICHOLAS BUSH TESTIFYING ON BEHALF OF THE NATURAL GAS SUPPLY ASSOCIATION BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION, SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

(Hearing Date: July 11, 1985; Response Date: August 30, 1985)

QUESTION 1:

"The NGSA testimony says that additions to natural gas reserves have fallen short of production every year since 1977 (p. 5). The AGA testimony says we have had a 'dramatic' turn around in our gas supply situation and that 1984 was the fourth consecutive year when additions to reserves nearly equalled or exceeded production (p. 11). How do you explain these differences?"

RESPONSE:

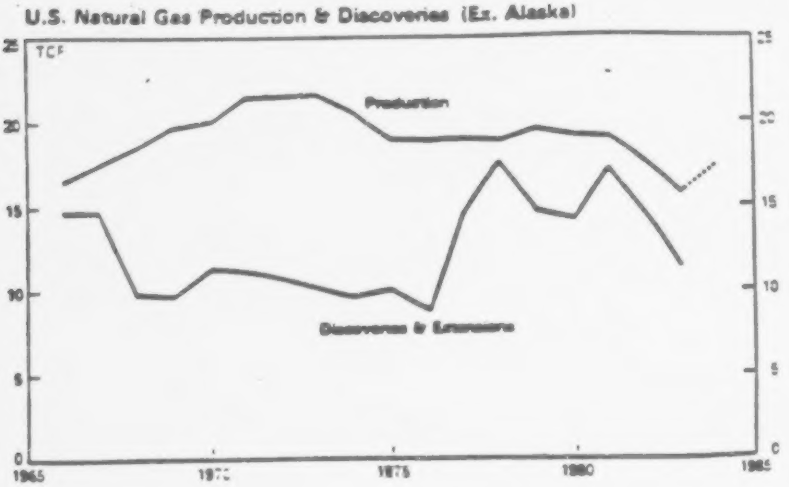
Insofar as this or any of the following questions pertain to NGSA's position regarding FERC's recently proposed rulemaking (Docket No. RM85-1-000), NGSA does not intend by these responses to supplant or amend its comments filed before the Commission on July 15, 1985, and made a part of the record in this proceeding by leave of Senator Nickles.

The difference between AGA's and NGSA's gas reserve figures lies in the fact that AGA includes revisions and adjustments in its annual figures, while NGSA relies only upon the figures which show actual discoveries and extensions of reserves. Additions to U.S. proved natural gas reserves are made up of two parts. One part measures the new gas reserves added in the reported year. This part of reserve additions consists of discoveries (new fields and new reserves in old fields) plus extensions to existing reservoirs in old fields.

The second part of annual additions to proved reserves, "adjustments and revisions," applies to proved reserves from prior years. This part does not reflect any reserves actually discovered or extended during the reported year, but instead reflects corrections to previous reserve estimates. As would be expected, revisions and adjustments to prior estimates are sometimes positive and sometimes negative, and further, as might also be expected, these corrections average very near zero when viewed over a longer time period as the bottom line on Graph 1 (below) demonstrates.

Hence, in any trend analysis of natural gas reserve additions, the discoveries and extensions portion of proved reserves should be used, and the revisions and adjustments portion omitted. The latter adds a "noise factor" to the data, since it results in the reserve additions for the year shown to be unrepresentative of what actually happened in that year.

Graph 1 relates discoveries and extensions to production over the same time period:



GRAPH 1

The sharp downward trend in discoveries and extensions since 1981 (when the number of drilling rigs operating peaked) is apparent.* See Appendix A, attached hereto. Discoveries and extensions have fallen more rapidly than production, with the shortfall between gas found and gas produced increasing from 1.5 tcf in 1981 to 4.3 tcf in 1983. *Gas Facts: 1983 Data*, at 8 (American Gas Association, 1984). As indicated by Appendix A, in the seven years between 1978 and 1984 (years for which EIA has published relevant statistics), *net reserve additions* exceeded production in only two years (1978 and 1981). Reserve additions in 1984 totaled a scant 82.4% of production. See Appendix A; *Advance Summary of the U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves; 1984 Annual Report*, Table 11 (Energy Information Administration, Office of Oil and Gas, September 1985).

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* The peak in discoveries and extensions shown for 1978 in the graph appears to be an anomaly while the EIA was perfecting their data collection and analysis techniques. The EIA first published reserve data in 1977, with the American Gas Association (AGA) being the previous source of gas reserve statistics. The AGA continued to publish reserve statistics through 1979 to provide a three-year overlap with the EIA to insure consistency. The AGA data for 1978 was 10.4 tcf of discoveries and extensions versus 17.7 reported by the EIA. Discoveries and extensions correlate very closely with the number of rigs operating when the AGA data is used through 1979, and the EIA data thereafter, suggesting an anomaly in the EIA data while their collection and analysis techniques were being perfected.

In conclusion, the future natural gas supply outlook is not very encouraging despite the large size of the potential resource base. Annual reserve additions are not consistently keeping pace with production. The ongoing decline in the domestic natural gas reserve base will soon be followed by a commensurate decrease in domestic production capacity. This, in turn, could lead to greater reliance on imported crude oil and natural gas.

QUESTION 2:

"Your testimony says, in essence, that wellhead prices are declining while burnertip prices are increasing. Then you say that from 1981 - 1984 wellhead cost per Mcf rose 65¢ per Mcf while transmission and distribution charges rose $1.12. You say that transmission and distribution charges represent a pipeline's "margin," that is, the cost difference between the wellhead and the burnertip prices. What part of the increase in transmission and distribution charges is due to an increase in the cost of pipeline fuel during that period?"

RESPONSE:

Natural gas wellhead prices stabilized in the second half of 1984 (after exhibiting occasional declines as early as March, 1983); gas wellhead prices commenced a sustained drop in January, 1985. As discussed in NGSA's testimony before the Subcommittee, wellhead prices generally trended upward prior to the peak in February, 1984. While average wellhead prices were rising prior to the 1984 peak, downstream prices to consumers were rising at a much higher rate. Moreover, downstream prices continued to rise after wellhead prices stabilized.

During the period 1980-1983 (most recent four year period for which figures are available), major class A & B pipeline compressor fuel expenses showed a net increase of $0.0222 (2.22¢) per Mcf. Statistics of Interstate Natural Gas Pipeline Companies, 1983, Table 12 (Department of Energy, DOE/EIA-0145(83), Nov. 1984). See Attachment #6 to NGSA's testimony, and Appendices B & C, hereto. (Because current figures are not available from the EIA for 1984, NGSA utilized EIA pipeline compressor fuel expense figures for the period 1980-1983. During this period, pipeline margins increased by $1.38 per Mcf, of which roughly 2¢ per Mcf reflects increases in pipeline compressor fuel expenses.)

QUESTION 3:

"If I recall correctly, we had testimony before this Committee that shows the major portion of increases in transmission and distribution charges is due to an increase in pipeline fuel cost, and an increase in interest costs. Can you dispute that?"

RESPONSE:

Yes. As indicated in the response to Question 2, EIA figures reveal that pipeline compressor fuel costs increased by 2.22¢ per Mcf during the period 1980-1983. For the same period, net interest charges for major class A & B pipelines increased a total of $0.1164 (11.64¢) per Mcf. Statistics of Interstate Natural Gas Pipeline Companies, 1983, Table 12 (Energy Information Administration, Department of Energy, DOE/EIA 0145(83), Nov. 1984). See Appendix B. Total compressor fuel and net interest charges for pipelines increased $0.1386 (13.86¢) per Mcf during the period 1980-1983.

Thus, pipeline fuel and interest costs have increased less than 14¢ per Mcf during roughly the same period when total pipeline margins, including profit, rose by $1.12 per Mcf. See Appendix C.

QUESTION 4:

"You call the rate of increase in transmission and distribution costs an 'excess margin growth.' If the increase is due to fuel costs and interest costs, how can that be 'excess margin growth'?"

RESPONSE:

Where it can be demonstrated with actual or empirical evidence that an increase in pipeline transmission and distribution costs is directly, dollar for dollar, due to increases in pipeline compressor fuel and interest costs, the characterization of such pipeline margin increases as "excess" would not be appropriate.

However, NGSA does not accept the inference suggested by Question 4, to the effect that actual natural gas pipeline transmission and distribution charges have increased at a rate which caused pipeline margins to balloon by an additional 33% in four years, during a period when other pipeline costs and inflation stabilized or decreased. Indeed, concrete figures published by the Energy Information Administration contradict any such inference. See responses to Questions 2 & 3, supra.

QUESTION 5:

"You say on page 10 that pipelines are 'guaranteed' high rates of return. If pipelines fail to transport as much gas as they estimate they will in their rate cases, they will fail to recover their full allowed rate of return. How are pipelines 'guaranteed' high rates of return?"

RESPONSE:

Briefly stated, FERC establishes an allowed pipeline return on rate base pursuant to what are referred to as "rate case filings." The rate case filings establish the return (profit) on rate base which FERC determines is fair for each interstate pipeline under the circumstances.

If a pipeline miscalculates and fails to transport as much gas as it estimates it will transport in a rate case filing, the pipeline can simply file a new FERC rate case which states the prior under recovery and requests a new (higher) allowed return on rate base. If a pipeline recovers in excess of its FERC approved return rate, there is no penalty imposed and no mechanism which requires the pipeline to file a new rate case to repay the over recovery. These principles are discussed in greater detail below.

In "rate case filings," interstate pipelines request FERC approval of tariffs for the transport of natural gas volumes and related services. The level of the charges for transportation services provided by pipelines are based upon "test volumes." Test volumes correspond roughly to the average quantity of gas transported by a given pipeline over a specified period which is believed to be representative of the volume which a pipeline anticipates it will transport in a given future period to which the tariffs filed-for will apply.

In general, the charges related to the test volume are broken into two broad categories which represent a pipeline's fixed and a pipeline's variable costs. Most of a pipeline's fixed costs are volume independent while a pipeline's variable costs are usually volume dependent.

Since pipeline transportation volumes can fluctuate over time, FERC historically has permitted pipelines to be "conservative" in estimating test volumes. Rate case filing test volumes commonly under-represent to a significant degree the reasonably anticipated future pipeline natural gas transportation volumes.

It would appear from aggregate data on rates of returns that most major interstate pipelines have become markedly adept at achieving a return (profit) on rate base which is often far in excess of the weighted average allowed return on rate base permitted by FERC rate case decisions. If a pipeline miscalculates and under recovers, it can return to FERC with a new rate case filing seeking to recover the difference between the actual return rate and the FERC approved return on rate base.

Unfortunately, FERC does not by any formal means of which NGSA is aware, review or analyze the regularity or extent of discrepancies between pipeline test volumes and allowed rates of return used in FERC rate case filings and actual pipeline volumes and rate base returns.

APPENDIX A

Estimated U.S. Lower-48 Proved Natural Gas Reserves

(Bcf, Dry)[1]

Year	Net Adjustments and Revisions[2]	Total Discoveries[3]	Net Reserve Additions	End of Year Proved Reserves	Annual Production	Reserve Additions Production Ratio
1977	N/A	N/A	N/A	175,170	N/A	N/A
1978	1,688	17,719	19,407	175,988	18,589	104.4%
1979	- 3,371	14,688	11,317	168,738	19,029	59.5%
1980	1,225	14,162	15,387	165,639	18,486	83.2%
1981	4,346	17,210	21,556	168,693	18,502	116.5%
1982	619	14,455	15,074	166,522	17,245	87.4%
1983	3,510	11,447	14,957	165,964	15,515	96.4%
1984[4]	372	13,520	13,892	162,987	16,869	82.4%
1984 Change Over 1983				2,977		

[1] **Source:** U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, Energy Information Administration, DOE/EIA-0216, Annual reports for each year from 1977 to 1983.

[2] Net Adjustments + Revision Increases - Revision Decreases.

[3] New Field Discoveries + New Reservoir Discoveries in Old Fields + Extensions in Existing Reservoirs.

[4] **Source:** Advance Summary of the U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves: 1984 Annual Report, Table 11 (Energy Information Administration, Office of Oil and Gas, September 1985)

Appendix B

MAJOR CLASS A & B INTERSTATE PIPELINE STATISTICS RE: COMPRESSOR FUEL EXPENSES AND NET INTEREST CHARGES

	Compressor Fuel Expenses 1/ (Million $)	Net Interest Charges 1/ (Million $)	Total Expenses (Million $)	Natural Gas Imports, Producer Purchases, & Pipeline Production (Bcf) 2/	Compressor Fuel Expenses Per Mcf (¢/Mcf)	Net Interest Charges Per Mcf (¢/Mcf)	Total Expenses Per Mcf (¢/Mcf)
1978	391.6	845.7	1,237.3	11,273.4	3.47	7.50	10.97
1979	597.6	999.3	1,596.9	11,601.9	5.15	8.61	13.76
1980	803.1	1,219.7	2,022.8	12,046.2	6.67	10.12	16.79
1981	1,057.8	1,549.7	2,607.5	12,490.0	8.47	12.41	20.88
1982	1,118.9	1,907.6	3,026.5	11,222.9	9.97	17.00	26.97
1983	869.5	2,128.0	2,997.5	9,777.7	8.89	21.76	30.65
1983 Change over 1980:					2.22	11.64	13.86

1/ Source: Statistics of Interstate Natural Gas Pipeline Companies, 1983, Energy Information Administration, DOE/EIA-0145(83), November 1984. Compressor Expenses: Table 12, under Transmission Expenses. Net interest charges: Table 5, under Interest Charges.

2/ Source: Natural Gas Monthly, Energy Information Administration, DOE/EIA-0130 (85/04), April 1985 (Published June 1985), Table 15.

Appendix C

CALCULATED GROWTH IN NATIONAL TRANSMISSION AND DISTRIBUTION MARGINS
($/Mcf)

Year	Average Wellhead Price	Average Residential Price	Average Pipeline "Excess Margin" (Col. 2 minus Col. 1)
1980	1.59	3.68	2.09
1981	1.98	4.29	2.31
1982	2.46	5.17	2.71
1983	2.59	6.06	3.47
1984	2.63	6.06	3.43
1981 - 1984 Difference	0.65	1.77	1.38
1980 - 1983 Difference	1.00	2.38	1.12

Source: *Natural Gas Monthly*, April 1985," Energy Information Administration, (DOE/EIA-0130 (85/04)), published June 1985, Table 10.

RESPONSE
BY THE
NATURAL GAS SUPPLY ASSOCIATION (NGSA)
TO
QUESTIONS PROPOUNDED BY SENATOR FORD TO ALL WITNESSES TESTIFYING BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION, SENATE COMMITTEE ON ENERGY AND NATURAL RESOURCES

(Hearing Date: July 11, 1985; Response Date: August 30, 1985)

QUESTION 1:

"This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?"

RESPONSE:

Insofar as this or any of the following questions pertain to NGSA's position regarding FERC's recently proposed rulemaking (Docket No. RM85-1-000), NGSA does not intend by these responses to supplant or amend its comments filed before the Commission on July 15, 1985, and made a part of the record in this proceeding by leave of Senator Nickles.

Chairman O'Connor has stated before the Subcommittee that FERC's intention in propounding the NOPR is to minimize the distorting effect which government regulation introduces into the transmission of market signals from the wellhead to the burnertip. See, e.g., Statement of Raymond J. O'Connor Before the Subcommittee on Energy Regulation and Conservation, Committee on Energy and Natural Resources, U.S. Senate, at 2, (June 18, 1985). It seems evident, however, that FERC cannot completely achieve this goal so long as it is required to employ the NGPA formula for establishing maximum lawful ceiling prices for regulated old gas.

The solution is to authorize FERC to abandon the formula. Congress should now act to repeal the wellhead pricing provisions of the NGPA. Such action would encourage the optimum development of least cost natural gas supplies. Producers would also be encouraged to further develop lowest cost gas reserves since consumer and wellhead prices are falling. Legislation such as S. 1302, introduced by Senator Nickles, might represent an appropriate vehicle for accomplishing this objective.

In its comments filed before FERC, NGSA discusses in detail those sections of the NOPR which NGSA believes are beyond FERC's authority. See NGSA comments, Docket No. RM85-1-000 (Parts A-D), at 3, 6-13, 16-18 (July 15, 1985). Briefly, it is NGSA's contention that certain provisions (for example, the block-billing, unilateral contract abrogation, and buyout provisions) of the NOPR are not authorized since they would not serve to protect the public interest.

QUESTION 2:

"Would any witness oppose repealing incremental pricing and amending the Power Plant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?"

RESPONSE:

NGSA supports the repeal of the incremental pricing and demand restrictions set forth by the NGPA and the Power Plant and Industrial Fuel Use Act. Indeed, NGSA has repeatedly urged Congress to take just such action since the NGPA and Fuel Use Act constraints constitute artificial and unnecessary disincentives to the development of existing and potential gas reserves.

NGSA believes that repeal of the incremental pricing and use constraints imposed by the NGPA and by the Fuel Use Act should be coupled in Congress to a comprehensive program aimed at increasing competition in gas markets by:

(1) requiring non-discriminatory contract carriage of natural gas supplies;

(2) decontrolling expired and expiring natural gas sales contracts;

(3) providing incentives for old gas production enhancement activities;

(4) providing purchasers open and competitive access to all sources and categories of natural gas by eliminating artificial regulatory "jurisdiction" and "dedication" constraints.

A competitive and fair natural gas market will be achieved by a proper combination of statutory decontrol of natural gas at the wellhead, the elimination of restrictions on end-uses of natural gas, and appropriate adjustments to existing pipeline monopoly regulatory programs. Although they may be capable of adequately "protecting the public interest," neither the courts nor regulatory agencies can effectively achieve the goal of creating a truly competitive natural gas market open to all consumers.

QUESTION 3:

"If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?"

RESPONSE:

In its comments filed before FERC, NGSA discusses in detail the likely impact of the NOPR upon natural gas supplies. See NGSA comments, Docket No. RM85-1-000 (Parts A-D), at 11-13 (July 15, 1985). Because the short-term impact of the proposed block-billing procedure will be additional artificial pressure upon tight sands and deep formation gas prices, revenue losses to producers on sales of all gas will undoubtedly be substantial. Any drop in the level of producer revenues will be translated immediately into decreases in producer exploration and drilling budgets. Reduced levels of exploration and drilling inevitably result in lower reserves and, ultimately, higher natural gas prices to consumers.

NGSA believes that FERC and Congress have asserted in the past that a primary concern is to assure that domestic supplies of natural gas are continually developed and maintained at a rate adequate to keep pace with demand. With the issuance of the recent NOPR, FERC seems to be improperly diverting its attention to focus solely on short-term consumer prices for natural gas, at the expense of adequate future domestic gas supplies.

Further, with regard to consumer prices, FERC's proposed elimination of rolled-in pricing for natural gas at the "national" level in favor of a three part block-billing procedure will not eliminate or even reduce distortions caused in the market by past and present regulatory and legislative policies. If adopted, the tiered pricing system will merely move existing economic distortions down the marketing chain and thereby create an entirely new system of price distortions and discrimination.

INGAA

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August 30, 1985

Honorable Don Nickles
Chairman, Subcommittee on Energy
Regulation and Conservation
Energy and Natural Resources Committee
United States Senate
Washington, D. C. 20510

Dear Senator Nickles:

Enclosed are the responses of the Interstate Natural Gas Association of America (INGAA) to the follow-up questions referred by Sen. Wendell H. Ford to all the witnesses who appeared before the Subcommittee on July 11, 1985.

INGAA is the national trade association representing the interstate natural gas transmission industry. We appreciate your interest in the FERC NOPR and its potential impact on the industry and the nation's consumers of natural gas. We will be happy to provide further information to Senator Ford or any other members of the Subcommittee should that be helpful.

Sincerely,

Jerome J. McGrath /(S.)

Jerome J. McGrath
President

INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA
1660 L STREET, NORTHWEST, WASHINGTON, D.C. 20036-5611, TELEPHONE 202/293-5770

August 30, 1985

INGAA RESPONSE TO QUESTIONS BY SEN. FORD TO ALL WITNESSES
BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
July 11, 1985

Q.1. This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?

A. INGAA submits that the FERC does not need any new statutory authority to protect the public interest. Rather, it needs to modify the NOPR under its existing statutory authority along the lines set forth in INGAA's comments.

The FERC Notice of Proposed Rulemaking (RM85-1-000) raises basic questions as to the Commission's statutory authority to do what it has proposed. Some of the proposals raising significant legal questions include:

1) the proposal to deregulate Block 2 gas after four years;

2) the proposed de facto unilateral abandonment that would result from allowing a pipeline's existing sales customers to reduce their rates from pipeline suppliers at the maximum rate of 25% per year;

3) the proposed self-implementing transportation program which constitutes mandatory carriage by indirect means; and

4) the proposal to allocate Block 1 gas first to existing firm sales customers.

In our comments filed with the FERC, we questioned the Commission's statutory authority to implement these proposals and pointed out why they are not in the public interest.

Q.2. Would any witness oppose repealing incremental pricing and amending the Powerplant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?

A. INGAA favors amendment of the Powerplant and Industrial Fuel Use Act to repeal the demand constraints on natural gas. INGAA also favors repeal of incremental pricing.

Q.3. If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?

A. INGAA has not made any forecast of the impact of the NOPR on gas supplies and natural gas prices paid by consumers. However, INGAA is very concerned about the negative long-term impact of the NOPR on gas supply. The current surplus of deliverability has resulted in lower wellhead prices for gas. This, in combination with the NOPR could remove incentives for producers to explore for new supplies. To the extent this happens, the NOPR would adversely impact on assuring reliable long-term supplies.

On the question of consumer prices, INGAA is greatly concerned that many consumers will see increased gas costs if the NOPR is implemented as proposed. Some large users of gas may enjoy short-term savings as a result of spot purchases and "distress" sales of gas. However, many distribution companies and other users who will continue to depend on their pipeline supplier for gas may well indeed see increased costs. For example, if a pipeline loses sales and thus incurs additional take-or-pay obligations or receives lower than anticipated revenues, the remaining customers on the system would have to bear some of these costs, by paying higher prices for their gas.

William C. Terpstra
President

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August 30, 1985

Mr. Howard Useem
Professional Staff Member
Committee on Energy and Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Useem:

In response to your recent memorandum, I am attaching my responses to the follow-up questions you had on my appearance at the Subcommittee's oversight hearing on the current state of and the factors affecting the natural gas market.

Very truly yours,

SWB for
W C Terpstra

W. C. Terpstra

Attachment

ANSWERS TO QUESTIONS BY
SENATOR FORD FOR MR. TERPSTRA

1. Do you believe the NOPR encourages end-users to bypass distribution companies and get supplies direct from pipelines?

A. I believe that NOPR as proposed will not only encourage end-users to bypass distribution companies but also encourage distribution companies to bypass pipelines. Customers will attempt to maximize Block 1 purchases and avoid Block 2 purchases. If customers elect to utilize the increased options available under NOPR to serve their markets with other suppliers, pipelines must not be precluded from having the right to compete to retain or regain markets. The rules as to "bypass" must be the same for all participants.

2. Do you believe the block pricing method proposed by the NOPR will work?

A. No. Under the Commission's proposed block pricing structure, pipelines would have to artificially isolate their low cost Block 1 gas from their remaining Block 2 gas. The NOPR would penalize pipelines by retroactively changing the rules of the game. Also penalized would be those producers who have recently agreed to market responsive contracts. This is because pipelines would be required by NOPR to disproportionally lower the price under such contracts in an effort to make Block 2 marketable -- on average. Much of the Block 2 gas was developed under contracts negotiated during the period of gas shortages because customers were clamoring for supply at any price. The rigid price and take terms necessary to purchase such gas make the Block 2 gas unmarketable. Pipelines, therefore, will not be able to compete at the margin with, for example, new market entrants.

If block pricing is to be required, we suggest the following blocks:

Block I -- Old Gas
Block II(a) -- Market responsive contracts
Block II(b) -- Non-market responsive contracts

3. Do you have an evaluation of Natural's potential take-or-pay exposure under the NOPR?

A. Natural estimates that its potential take-or-pay exposure could be over $1 billion for 1986 alone under NOPR

4. Is the plan to finalize the NOPR by early fall practical or would a longer transition period be better?

A. The timing of when the NOPR is finalized or the length of the transition period is not as critical as the impact of the proposal. If adopted we must insure the rules are workable and beneficial to the industry and consumers. We must complete the transition without a lengthy period of uncertainty and without major damage to the industry.

5. In your opinion will the NOPR encourage or discourage new gas supply drilling?

A. The NOPR will discourage new gas supply drilling. The effect of NOPR will create an unmarketable Block 2 while at the same time force gas prices down. With declining prices and long-term, high-cost supplies shut-in, drilling for new supplies will be uneconomical.

6. Do you believe the level of Block 1 gas supply is adequate to serve the needs of firm consumers?

A. Block 1 gas will not be adequate to serve the needs of firm consumers. Natural's sales for Fiscal 1985 are projected to be around 900 Bcf. Its Block 1 supplies total only about 450 Bcf with only 200 Bcf of that covered under pure Block 1 contracts. The remaining 250 Bcf falls under contracts covering both Block 1 and Block 2 gas.

7. How does the NOPR effect service reliability?

A. Service reliability under NOPR will be reduced. Operating a pipeline is a vital, dynamic function. On any given day a pipeline must match the needs of numerous customers with the output of thousands of supply sources. It can only do so by operating its system as an integrated whole, utilizing field supplies, storage, exchanges with other pipelines, etc., to get gas where it is needed. Any end-user could not reasonably expect to find a supply source or set of sources of a size necessary to meet its needs exactly. Clearly, a pipeline which can call on many sources, as well as storage is in a better position to render adequate service than is an individual buyer tied to a limited number of sources. If wells dedicated to a specific transportation customer freeze off -- to cite one specific example -- the pipeline no longer has the right, much less the obligation, to divert gas from other wells or from storage to assure adequate service.

8. Your testimony indicates that you have "concerns" that FERC has exceeded its legal authority in the NOPR. How has it done so?

A. Natural is concerned that the Commission's legal authority to implement NOPR will be questioned, given the significant proposed changes in the relationships between producers, pipelines, distributors and end-users. While many of the proposals of NOPR are termed "voluntary," pipelines will be forced to accept the rules and all the conditions that go with them if they want to survive. The key to reducing potential litigation is to strike a balance. If the pipelines, the distributors and producers all share in the pain, I think it would stand a better chance than if rights are heavily weighted toward one segment and obligations toward another.

ANSWERS TO QUESTIONS BY SEN. FORD FOR ALL WITNESSES BEFORE
THE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
JULY 11, 1985

1. This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?

A. The problem we have is, over the last 30 or 40 years the entire industry has been built on long-term contracts, adequate gas supply, service obligations and stable regulations. We have been building a supply based on the fact that we are in the merchant function. If the FERC wants us to move to being a transporter or a more market-oriented industry, that's fine. But we've got contracts that obligate us to purchase 76 Tcf of gas and if our customers are going to be permitted to have additional flexibility, we need a mechanism to reduce our contractual obligations. The only way for this to work is to condition producer access to transportation on take-or-pay relief. If FERC lacks the legal authority to do this, then a new statute may be needed.

2. Would any witness oppose repealing incremental pricing and amending the Powerplant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?

A. No.

3. If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?

A. The block pricing feature of NOPR will divide gas supply into two blocks. The proposed second block is presently not marketable. Customers will attempt to maximize Block 1 purchases and avoid Block 2 purchases. Bypass of pipelines by distribution companies will result and end end-users will attempt to bypass distribution companies. The effect of these dislocations in the long-run will be higher costs to residential users and perhaps a shortage of gas supply as we fully expect NOPR to discourage drilling.

8-30-85

AGA American Gas Association

1515 Wilson Boulevard, Arlington, Va. 22209
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Michael Baly III
Vice President
Government Relations

August 30, 1985

Mr. Howard Useem
Subcommittee on Energy Regulation
  and Conservation
Committee on Energy and Natural Resouces
United States Senate
Washington, DC 20510

Dear Howard:

We are pleased to present our answers to the follow-up questions regarding A.G.A.'s July 11, 1985 appearance before your Subcommittee on the status of the natural gas industry. I hope that these answers satisfy your needs.

If I can be of further service to you as you attempt to deal with the complex issues raised in the July 11 hearing, feel free to call.

Respectfully,

Mike

Michael Baly III

MB/lm

Enclosure

AMERICAN GAS ASSOCIATION RESPONSES TO QUESTIONS FROM
THE SENATE SUBCOMMITTEE ON
ENERGY AND REGULATION AND CONSERVATION

August 30, 1985

1. This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?

Although it is our view that some aspects of the FERC's Notice of Proposed Rulemaking (NOPR) are legally questionable, we do not believe that the basic problem is a lack of adequate statutory authority for the Commission to deal with issues such as take-or-pay liability. Instead, the basic problem is that the Commission has proposed specific approaches which are legally debatable--while overlooking alternative approaches that would be more effective and that would fall more clearly within the Commission's existing statutory authority.

In our comments and oral testimony before the Commission, we have brought such alternative approaches to the Commission's attention. Specifically:

a. With respect to the block pricing proposal, we have not asserted that any temporary departure from rolled-in pricing would be legally unsound. We have instead asserted that any such temporary departure from rolled-in pricing must be fully justified--with one key element of this justification being a favorable impact on the community of natural gas consumers. The current Commission proposal may fail this test. By creating a single Block Two that lumps market-sensitive gas together with rigidly above-market gas, the currently proposed Block Two dilutes the price impact of gas that is already market-sensitive and erodes the ability of pipelines to offer higher "takes" as an inducement for renegotiation of above-market gas. As a result of these two factors, the currently envisioned block pricing scheme could actually increase the amount of pipeline take-or-pay liability that must be recovered from established pipeline customers. Such developments would hardly serve the interests of gas consumers and, in the face of such developments, it would be difficult for the Commission to maintain the "public interest" rationale that is needed to justify a temporary shift from rolled-in pricing.

However, this flaw can be easily remedied by simply sub-dividing Block Two into two sub-categories: Block 2a, which would be composed of gas under contracts which are "market-sensitive" and/or which post-date the effective date of the new rule; and Block 2b, which would contain gas under those existing contracts which are not "market-sensitive". Through this simple step of sub-dividing Block Two, block pricing could be turned into a tool for rewarding producers who have agreed to "market-sensitive" contracts--and for increasing the pressure on "holdout" producers who are clinging to rigidly above-market gas. With this simple action, the negative impact of the current proposal could be reversed, a weak "public interest" justification could be converted into a strong one, and a potentially major legal shortcoming could be avoided.

Another defect in the current block pricing proposal could be remedied just as easily. At present, the proposal implies that pipelines should nominate gas volumes by block at the wellhead: that is, the proposed rule appears to contemplate that pipelines can control how much gas they take from each of the blocks. However, the proposal is silent on how pipelines should deal with "multi-vintage" contracts--which cover gas from a number of different NGPA pricing categories and which reserve to the producer the right to determine the "mix" of gas that will flow from each pricing category. If the effectiveness of the block pricing approach is to be maximized, pipelines need from the Commission an explicit Order that they should nominate gas volumes by block at the wellhead. Such a policy would help to resolve a legal quandary for the pipelines and, by providing a stronger force majeure basis for overriding "multi-vintage" contracts, could speed the pace of contract renegotiation.

Incidentally, this Committee should not complacently assume that the problem of above-market gas contracts will automatically resolve itself over time. According to a study (which is attached) that was conducted for us this month by Foster Associates, roughly 1.6 trillion cubic feet of interstate gas production--over 50% of all NGPA Section 102 and 107 interstate gas and over 10% of all interstate pipeline supply--is currently governed by rigidly above-market contracts. The average wellhead price of this gas is $4.49 per MMBtu's. This compares with an average price of $3.78 per MMBtu's for NGPA Section 102 and 107 interstate gas volumes as a whole; $3.02 per MMBtu's for "market-sensitive" NGPA Section 102 and 107 interstate gas volumes; and $2.64 per MMBtu's for all interstate gas.

Thus, the above-market gas is far above market. Further, the natural process of contract expiration will not substantially ease this problem for quite some time. According to the Foster Associates study, only 13% of the above-market contracts will expire by 1990--and only 74% will expire by 1995. Thus, if interstate pipelines are not given adequate tools for contract renegotiation, this pocket of above-market gas could be distorting average wellhead prices for a long time.

b. With respect to take-or-pay-relief, we have recommended that the Commission should pursue less costly --and more flexible--alternatives to the proposed "buy-out" approach. These alternatives include the following:

1) Making take-or-pay relief a pre-condition for producer access to blanket certificate transportation.

2) Making take-or-pay relief a pre-condition for expedited release and abandonment.

3) Permitting pipelines to give producers who have negotiated "market-sensitive" contracts a priority access to blanket certificate transportation.

4) A Commission ruling that, where make-up of untaken price-controlled gas volumes is unlikely, take-or-pay liability is voided to the extent that such payments would lead to unit prices per MMBtu's that exceed the applicable NGPA price ceiling.

In our view, all of the above steps can be taken without conferring any new statutory authority upon the Commission. In fact, given the FERC's obligation to enforce the NGPA, Commission action to take the fourth of these steps may be not merely a legal option but an affirmative legal duty.

c. With respect to expedited certificates, we believe that the basic concept is attractive and legally sound. However, the proposal has two small--but potentially very serious--flaws:

1) The failure of the proposed rule to state explicitly that expedited certificates for distribution company bypass will not pre-empt whatever State authority may be applicable; and

2) The failure of the proposed rule to provide

> that--so long as no existing pipeline customers are adversely affected--a pipeline which acts under an expedited certificate may negotiate voluntary agreements to share risks between the pipeline and the new or incremental customers.

As in the case of other policies embodied in the NOPR, these flaws can be easily remedied--without any necessity for Congressional involvement in the authorship of new statutory authority.

Another A.G.A. recommendation is that the standards for approval should be the same for both bypass of distributors (under the expedited certificates) and bypass of pipelines (under NGPA Section 311 sales taps). Like our other policy recommendations, this change can also be implemented without recourse to new legislation.

d. With respect to non-discriminatory transportation, the Commission's proposal was so broad in nature--and so lacking in important specifics--that it was difficult for us to identify areas of specifically legal concern. Instead, we recommended that the Commission should convene a Technical Conference--to explore the "nuts and bolts" questions--and we offered our own detailed recommendations in many areas, such as capacity allocation, that the proposed rule did not address. We are confident that the Commission could implement all of our recommendations on transportation without having to come to Congress for a new statute.

All in all, we are hopeful that the Commission's new rule--if sensibly revised where appropriate--will be a significant improvement over the status quo. We are doing whatever we can to help the Commission to act wisely--because we would frankly prefer to see the problems involved addressed by the Commission, which is knowledgeable about our industry and has the authority to act flexibly. Legislators, addressing the same problems in a statute, would of necessity have to gravitate toward more fixed and uniform approaches; such approaches might be too rigid for an industry that is increasingly subject to market-induced changes.

2. Would any witness approve repealing incremental pricing and amending the Powerplant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?

A.G.A. has long favored repeal of incremental pricing as well as repeal of the fuel choice restrictions in the Powerplant and Industrial Fuel Use Act (including the restrictions on oil as well as gas). We believe that the marketplace, not the Federal Government, should determine what energy sources are used in new facilities--and we are confident of our industry's ability to hold its own, in its competition against coal and other energy sources, on the basis of both price and improved supply security.

The case for repealing the FUA restrictions can be briefly summarized as follows:

a. FUA precludes opportunities to save money for gas consumers. By automatically banning the use of gas or oil in large new factories and powerplants, FUA legally blocks otherwise available gas industry opportunities to compete for new sales. Thus, each gas consumer may have to pay a greater share of fixed system costs--that is, a higher utility bill than might otherwise be necessary.

b. FUA discourages promising new technologies. A special exemption is needed for use of gas in cogeneration--despite cogeneration's high energy conservation potential. No FUA exemptions at all are available for two other promising technologies: 1) The "select use" of natural gas--as a secondary fuel, in conjunction with coal or residual oil--for purposes of reducing emissions that would otherwise occur. 2) Gas for modular, combined cycle generators in new powerplants--which can reach a new high in energy efficiency, thereby giving the electricity consumer the same energy for fewer dollars.

c. FUA could be a major "drag" on economic growth. A recent A.G.A. analysis, which attempted to quantify the "worst case" economic impact of retaining FUA, found that FUA could cause a cumulative drop in gas demand of as much as 26.2 trillion cubic feet by the end of the century. If this gas demand were replaced by direct coal use and coal-generated electricity, the added economic burdens--in 1984 dollars, over the next 15 years--could be as much as: 1) $43.7 billion in otherwise unnecessary capital investment; and 2) $11.5 billion in added costs of generating electricity. Also, there could be major increments of new, otherwise avoidable pollution. If the affected new powerplants and factories were instead not built at all, and were replaced by imported goods and electricity, the cumulative "drag" on the economy could: 1) eliminate up to 1.5 million otherwise available jobs; plus 2) boost the balance of trade deficit by up to $1,160 billion.

d. FUA repeal would not stop the market-driven trend toward increased use of coal. Although specific projections differ, numerous informed observers--DOE, A.G.A. and the National Coal Association--all foresee coal demand rising by 50% or more in the next 10-15 years. This trend is far too strong to be reversed by FUA repeal. Indeed, by permitting greater reliance on "select gas use" for pollution control, FUA repeal may actually increase demand for high sulfur coal.

The case for incremental pricing repeal can be briefly summarized as follows:

a. Incremental pricing precludes opportunities to reduce the use of imported oil. For industrial boilers, incremental pricing automatically boosts the gas price up to rough parity with the price of residual oil (even if gas would otherwise be cheaper). Saddling natural gas with this pricing "handicap"--in its competition with imported oil--makes no sense if a free market and energy self-sufficiency are truly national goals.

b. Incremental pricing has not met its intended objectives. In practice incremental pricing: 1) has provided little--if any--cross-subsidization of residential gas bills; and 2) has had no apparent restraining effect on wellhead prices.

c. Incremental pricing distorts "gas against gas" competition. Because industrial boilers can avoid incremental pricing by shifting to carriage, or by relocating to a gas-producing State where intrastate market supplies are available, incremental pricing can artificially "tilt" a user's choice among competing gas suppliers.

We stress that the Committee already has before it an excellent vehicle for repeal of these artificial and unreasonable constraints on natural gas demand. S. 1251, sponsored by Senators Peter Domenici (R-NM) and Bennett Johnston (D-LA), would strike both of these restrictive programs from the statute books--without tying such action to other, more contentious issues on which a Congressional consensus is less clearly established.

3. If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?

If implemented as proposed, the NOPR would lower the price of both domestic and Canadian gas, but would substantially increase take-or-pay liabilities of pipelines. Over the short-term, these two events would tend to counteract each other. The average price of Block Two gas today is $3.48/MMBtu -- with spot gas selling on average for about

$2.25/MMBtu. As currently structured, the NOPR does not facilitate the renegotiation of Block Two gas to marketable levels. The combination of a large unmarketable amount of Block Two gas, a large gas bubble (estimated at 2.9 Tcf by the A.G.A.), and the availability of expedited non-discriminatory transportation will result in large amounts of shut-in Block Two gas. The fact that this gas is under long-term contracts, with take or pay clauses, will result in large take-or-pay liabilities being incurred by interstate pipelines. The FERC (in its rule) anticipates that these take-or-pay payments, and/or "buyouts" of take-or-pay liability, will be passed on to consumers. Obviously, as higher priced Block Two gas is replaced by much lower priced spot or uncommitted gas, as well as renegotiated Block Two contracts, the wellhead price will fall dramatically. Given the present take-or-pay "buyout" provision in the NOPR, it is impossible to quantify whether this decline in field prices will outweigh the increased take-or-pay payments by pipelines to producers.

A principal assumption underpinning the gas pricing block structure (as presently written), and especially the take-or-pay "buyout" provisions, was that the higher priced gas contracts are short-term and likely to expire over the next few years. This assumption is wrong. As we noted in our response to Question 1, A.G.A. had Foster Associates conduct a study (which is attached) on the expiration dates of high priced gas contracts and that study concluded that only 13% of the current high cost gas purchases are flowing under contracts that terminate prior to 1990. This data indicates that take-or-pay "buyout" payments--to the extent that the producers will agree to such "buyouts"--are likely to be very costly to gas consumers.

The proposed FERC rule may not have a major impact on overall natural gas supplies. As previously mentioned, the market for spot and uncommitted gas is currently down to $2.25/MMBtu and is unlikely to fall further as a result of the NOPR. In fact, lower average gas prices resulting from the NOPR should increase gas demand, thereby increasing gas takes and spot gas prices. Thus, the NOPR should not negatively impact the cost of new gas drilling. On the other hand, as previously discussed, the NOPR should result in higher priced gas already under contract either falling in price or being shut-in. This will result in reduced producer revenue and could further seriously impair drilling programs of independent producers. One of the impacts of the NOPR on gas supplies is therefore focused on the financial impacts on independent producers rather than any major change in the price for uncommitted gas.

Finally, as presently structured, the NOPR will render unmarketable much of the Block Two gas that is now under contract to interstate pipelines. This will result in interstate pipelines suspending purchases for new, uncommitted gas because: 1) they would have to roll new purchases in with non-competitive Block Two gas; and 2) they would already be incurring significant take-or-pay liability for untaken Block Two gas. The absence of interstate pipeline purchasers from the wellhead market will result in unnecessary confusion that could delay drilling activity.

The short-term gas supply picture is very positive. The excess deliverability situation (bubble) in the field should persist until the end of the decade -- although it will gradually contract throughout the 1985-90 period. (See the attached A.G.A. bubble analysis.) The fundamentals of the short-term gas supply/demand situation remain: 1) a slow increase in requirements; 2) a sharp increase in Canadian gas availability; and 3) relative stability in domestic deliverability. The strength in the domestic deliverability outlook is reinforced by: (a) the 8.8 percent increase in U.S. gas well completions between 1983 and 1984; and (b) the 21.5 percent increase between the first quarter of 1984 as contrasted with the first quarter of 1985. The NOPR will probably not materially affect the fundamentals of this gas supply/demand outlook.

Amending the block pricing provision -- along the lines set forth in our response to Question 1 -- would solve some of the supply problems that would otherwise be created by the NOPR. It would facilitate contract renegotiation, thereby easing the take-or-pay problem. It would allow pipelines greater flexibility in buying new gas, thereby eliminating some confusion in the field. In addition, such a subdivided Block Two could better accommodate problems associated with multi-vintage gas contracts and State prorationing rules (an area already subject to extensive litigation).

4. (Question from Senator Ford) The A.G.A. testimony says we have had a "dramatic" turnaround in our gas supply situation and that 1984 was the fourth consecutive year when additions to reserves nearly equalled or exceeded production (p. 11). The NGSA testimony says that additions to natural gas reserves have fallen short of production every year since 1977 (p. 5). How do you explain the differences?

These differences are relatively straightforward. The A.G.A. reference was based largely on EIA reserve information. In the four year period of 1981-1984 (inclusive) the U.S. reserves for the lower-48 states remained stable, i.e., reserve additions roughly equalled production. Table 1 is a tabulation of EIA data for 1981-1983 and the A.G.A. projection based on gas production company annual reports for 1984.

The NGSA did not comment on total reserve additions; they only commented on new discoveries -- a component of total reserve additions. The exclusion of revisions is a serious mistake, and would result in the consistent underestimating of reserve additions. First, discoveries only would not reflect any changes in technology that permit greater recovery of gas. For example, the trend towards lower abandonment pressures in producing fields would be ignored.

EIA defines revisions as "changes ... resulting from new information ... the installation of improved recovery techniques or equipment ... correction of previous reserves estimates." To omit these factors is to use less than the total available information. Similarly, discoveries do not include the net adjustments which EIA defines as "... the yearly changes .. that cannot be attributed to the estimates for other reserve change categories, due to the survey and statistical estimation methods employed...."

Revisions and net adjustments in the 1981-1983 period have generally been positive, i.e., increasing reserves. However, the great decline in reserves in the late 1960s and early 1970s was due in part to large negative revisions reported by the major oil companies. For example, from 1969 through 1976 (inclusive) there were 9.3 Tcf of negative revisions and these negative revisions were a factor in decreasing total U.S. reserves from 275 Tcf to 216 Tcf.

The total inventory of proved reserves is what counts and so our A.G.A. estimates focus on changes in total reserves. We believe that the exclusion of certain proved reserves simply because they were not estimated in the year in which the producing wells were drilled is without merit.

Table 1

PRODUCTION AND RESERVE ADDITIONS 1981-1984

	L-48		Neglecting North Slope		Total U.S.	
	Reserve Adds.	Production	Reserve Adds.	Production	Reserve Adds.	Production
1981[1]	21.56	18.50	21.28	18.66	21.45	18.74
1982[1]	15.07	17.25	16.26	17.43	17.29	17.51
1983[1]	14.96	15.52	13.64	15.71	14.52	15.79
1984[2]	17.51	16.93	17.51	17.13	18.64	17.22
Total 1981-1984	69.10	68.20	68.69	68.93	71.90	69.26
Average Replacement	$\frac{69.10}{68.20} = 1.01$		$\frac{68.69}{68.93} = .997$		$\frac{71.90}{69.26} = 1.04$	

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1. EIA "U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves".

2. A.G.A. "Preliminary Findings Concerning 1984 Natural Gas Reserves," May 3, 1985.

ANALYSIS OF HIGH COST GAS PURCHASES
BY CONTRACT TERMINATION DATE

Prepared for:

POLICY EVALUATION AND ANALYSIS GROUP
THE AMERICAN GAS ASSOCIATION

Prepared By:

FOSTER ASSOCIATES, INC.
Washington, D.C.

August 1985

ANALYSIS OF HIGH COST GAS PURCHASES BY CONTRACT TERMINATION DATE

INTRODUCTION

Foster Associates, Inc. has prepared this report on behalf of the American Gas Association.* The purposes of the report are: (1) to identify current high cost gas transactions (e.g., those without market responsive pricing provisions within the gas purchase contract) and (2) to determine the contract termination dates of these transactions. No attempt was made to estimate the level of reserves behind these high cost gas purchases, nor the projected volumes that would be expected upon contract termination date. This analysis focuses solely on current purchases of NGPA Sections 102 and 107 interstate gas, with contract dates prior to January 1, 1982.

SOURCES OF DATA AND METHOD OF ANALYSIS

Foster Associates' Online PGA Data Retrieval Service is a computerized database providing access to currently effective Purchased Gas Adjustment (PGA) filings by the major interstate pipelines with FERC. This database is the primary source of information for this report. Table 1 on the following page lists the pipelines currently in the database, the effective date of their PGAs and the dates of the actual and projected gas volume and cost information in the filing. These pipelines, in the composite, purchase approximately 9.2 Tcf of U.S. field production, representing the vast majority of purchases in the interstate market, and 54 percent of the total U.S. natural gas production. This database includes all of the pertinent information required to complete this study (e.g., contract date, NGPA category, producing area,

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* William G. Foster and Rebecca Reddick were responsible for the preparation of this study.

August 1985

Table 1

PIPELINE PGA DATES AND DOCKETS
CURRENTLY IN ONLINE PGA DATA RETRIEVAL SERVICE

Pipeline Name	Effective Date	TA Docket No.	Actual Data	Projected Data
ANR Pipeline Co.	05/01/85	85-2-48	12 mos. ended 01/31/85	12 mos. beginning 05/01/85
Arkla Energy Resources	04/01/85	85-2-31	6 mos. ended 12/31/84	6 mos. beginning 04/01/85
Colorado Interstate Gas Co.	10/01/84	85-1-32	12 mos. ended 12/31/83	12 mos. beginning 10/01/84
Columbia Gas Transmission Corp.	03/01/85	85-1-21	6 mos. ended 08/31/84	6 mos. beginning 03/01/85
Consolidated Gas Transmission Corp.	03/01/85	85-1-22	6 mos. ended 10/31/84	6 mos. beginning 03/01/85
El Paso Natural Gas Co.	04/01/85	85-2-23	6 mos. ended 12/31/84	6 mos. beginning 04/01/85
Florida Gas Transmission Co.[e]	04/01/85	85-3-34	6 mos. ended 12/31/84	6 mos. beginning 04/01/85
KN Energy, Inc.	12/01/84[a]	85-1-53	12 mos. ended 05/31/84	12 mos. beginning 12/01/84
Mississippi River Transmission Corp.	03/01/85	85-2-25	12 mos. ended 12/31/84	12 mos. beginning 05/01/85
Mountain Fuel Resources	06/01/85	85-2-55	12 mos. ended 01/31/85[c]	12 mos. beginning 06/01/85
Natural Gas Pipeline Co. of America	03/01/85	85-1-26	6 mos. ended 10/31/84[b]	6 mos. beginning 03/01/85
Northern Natural Gas Co.[e]	01/01/85	85-3-59	12 mos. ended 07/31/84	12 mos. beginning 01/01/85
Northwest Central Pipeline Co.	4/23/85	85-2-43	6 mos. ended 01/22/85	6 mos. beginning 04/23/85
Northwest Pipeline Corp.	04/01/85	85-3-37	12 mos. ended 12/31/84	12 mos. beginning 04/01/85
Panhandle Eastern Pipe Line Co.	03/01/85	84-1-28	6 mos. ended 11/30/84	6 mos. beginning 03/01/85
Sea Robin Pipeline Co.	07/01/85	85-2-6	6 mos. ended 03/31/85	6 mos. beginning 07/01/85
Southern Natural Gas Co.	10/01/84	85-1-7	6 mos. ended 06/30/84	6 mos. beginning 10/01/84
Tennessee Gas Pipeline Co.	07/01/85	85-2-9	6 mos. ended 02/28/85	6 mos. beginning 07/01/85
Texas Eastern Transmission Corp.	07/01/85	85-3-17	12 mos. ended 03/31/85	12 mos. beginning 07/01/85[d]
Texas Gas Transmission Corp.	02/01/85	85-1-18	6 mos. ended 09/30/84	6 mos. beginning 02/01/85
Transcontinental Gas Pipe Line Corp.	05/01/85	85-2-29	6 mos. ended 10/31/84	6 mos. beginning 05/01/85
Transwestern Pipeline Co.	04/01/85	85-2-42	12 mos. ended 11/30/84	12 mos. beginning 04/01/85
Trunkline Gas Co.	09/01/84	84-1-30	12 mos. ended 05/31/84	12 mos. beginning 09/01/84
United Gas Pipe Line Co.	07/01/85	85-2-11	6 mos. ended 03/31/85	6 mos. beginning 07/01/85

a/ Not yet available.

b/ Data reported by Company on 12-month basis; converted to 6-month data by Foster Associates to conform with projected data.

c/ Data reported by Company on 5-month basis; converted to 12-month data by Foster Associates to conform with projected data.

d/ Data reported by company on a 7-month basis; converted to 12-month data by Foster Associates to conform with projected data.

e/ Revised PGA filing.

volume and prices) except for the individual contract terms. Contract terms have been independently researched for a sample of the transactions.

The steps taken in the preparation of this study are:

1. Access the Online PGA Data Retrieval Service to identify gas purchase transactions meeting the following criteria:

   - NGPA Sections 102 and 107 purchases, with
   - Contract dates prior to January 1, 1982, and
   - Projected prices greater than $3.80 per MMBtu.

   The $3.80 per MMBtu price was chosen to represent the minimum price of transactions under contracts without market responsive provisions (e.g., no market-out or economic clauses). The current NGPA Section 102 ceiling price, adjusted downward for Btu content, is the basis of the $3.80 per MMBtu.

   In total, 1.6 Tcf of annual gas purchases fall under the specified criteria; the current average price of these gas purchases is $4.49 per MMBtu. These purchases represent 17 percent of the major interstate pipelines' total domestic purchases, and 15 percent of the pipeline's total purchases (i.e., including imports, but excluding interpipeline transactions).

2. A sample of large volume transactions (i.e., greater than 200 MMcf per year) was chosen from all high cost gas purchases for the purpose of identifying their contract terms. Contract studies

available at Foster Associates and other available contract information were used as the source of this term information. In total, about 300 contracts were used for the sample, including a large number of available OCS contracts.[1] The sample represented about 27 percent of the total high cost gas purchases falling under the specified criteria.

3. The high cost gas purchases were arrayed by contract date (pre-1965, and for each year 1965 through 1981), and by producing area (OCS, Onshore Louisiana, Onshore Texas and other areas).

4. The sample of high cost gas purchases was then arrayed by the same criteria as stated above for all transactions (see No. 3), plus contract termination dates.

5. The contract termination dates of the sample were applied to the high gas cost purchases for the corresponding contract dates and producing areas, to determine the distribution of all high cost gas by contract termination date.

It should be emphasized that the high cost gas volumes reported here represent current gas purchases, and are not projected volumes upon contract termination date. The projected volumes of high cost gas upon contract termination date could be higher or lower. Factors understating these volumes include current "shut-in" volumes, the exclusion of intrastate purchases and the possibility of additional high cost gas coming on-line under pre-January 1, 1982 contracts. On the other hand, the volume would be lowered over time by applying an expected production decline curve. This is particularly important in the case of high cost gas because of the large proportion of this gas that is being produced in the OCS (i.e.,52 percent), where the decline curve is generally higher than the onshore areas.

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[1] Transactions dealing with OCS gas represent 52 percent of the total high cost gas purchases.

RESULTS

About 38 percent of the total interstate gas purchased is NGPA Sections 102 or 107 gas. These categories of gas are some of the highest priced sources in the U.S.; for example, the average price of all Section 102 and Section 107 interstate gas purchases is $3.78 per MMBtu, compared with an average price of all field purchases at $2.64 per MMBtu.

There is a striking dichotomy of gas purchases by contract date governing the Section 102 and Section 107 purchase categories. This contractual dichotomy is between purchases with market sensitive pricing provisions vis-a-vis purchases at a much higher non-market sensitive price.

Table 2 shows a summary of these purchases by market sensitivity and by contract date (pre and post-January 1, 1982). In total, approximately 52 percent of all interstate Sections 102 and 107 gas purchases fall under the non-market sensitive category, with an average field price of $4.49 per MMBtu. Almost 90 percent of this gas was contracted for prior to January 1, 1982. The primary reason for this occurrence is the fact that market out and/or economic clauses are only evident in provisions of gas contracts executed after that date.

Table 2

SUMMARY OF NGPA SECTIONS 102 AND 107
INTERSTATE PIPELINE GAS PURCHASES
(Mid 1985)

	Volume (12 Months) (MMcf)	Price ($/MMBtu)
Pre Jan. 1, 1982 Contracts		
Market Sensitive	713,302	3.12
Non-market Sensitive	1,561,895	4.49
Total	2,275,197	4.05
Post Jan. 1, 1982 Contracts		
Market Sensitive	963,494	2.95
Non-market Sensitive	233,404	4.50
Total	1,196,898	3.26
Total		
Market Sensitive	1,676,796	3.02
Non-market Sensitive	1,795,299	4.49
TOTAL	3,472,095	3.78

Source: Foster Associates' Online PGA Data Retrieval Service.

A primary purpose of this report is to determine the contract termination date of the current high cost (non-market sensitive) gas purchases.[1] To do so, it is useful to segregate these purchase volumes by contract date and producing area. Table 3 shows this distribution, and Chart 1 presents cumulative purchases by contract year.

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[1] For contracts executed prior to January 1, 1982.

Table 3

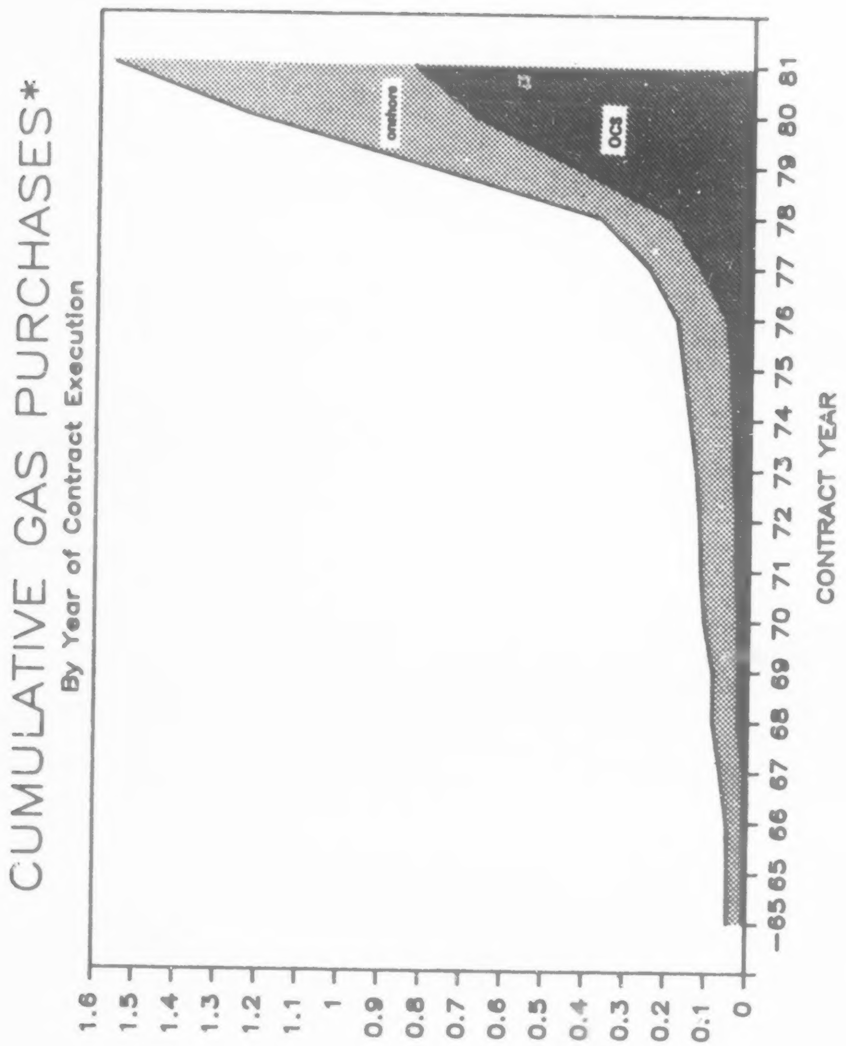
HIGH COST GAS PURCHASES BY YEAR OF CONTRACT AND PRODUCING AREA

(12 Month Volumes - MMcf)

Contract Year	OCS	LA Onshore	Texas Onshore	Other	Total
Pre 1965	6,716	17,806	13,120	8,278	45,920
1965	--	1,874	--	48	1,922
1966	--	--	1,406	1,562	2,968
1967	66	11,246	3,905	1,562	16,779
1968	17,649	54	--	1,718	19,421
1969	--	--	142	937	1,079
1970	4,217	214	--	18,118	22,549
1971	8,278	--	--	1,250	9,528
1972	312	--	1,093	2,343	3,748
1973	9,840	--	469	2,343	12,652
1974	2,343	1,874	106	16,556	20,879
1975	6,716	1,406	3,749	5,467	17,338
1976	9,528	5,935	469	1,093	17,025
1977	63,882	1,250	118	3,124	68,374
1978	75,440	4,998	12,808	29,051	122,297
1979	227,880	12,495	67,786	107,203	415,364
1980	228,034	28,938	22,120	121,975	401,067
1981	148,380	64,975	26,084	123,546	362,985
Total	809,281	153,065	153,375	446,174	1,561,895

Source: Foster Associates' Online PGA Data Retrieval Service.

Chart 1



*NGPA 102 and 107, high cost gas, and contracts executed before 1982

Several interesting facts are evident from these data:

1. About 52 percent of the high cost gas currently being purchased is produced on the Outer Continental Shelf (OCS) of Texas and Louisiana.[1]

2. Texas Onshore and Louisiana Onshore producing areas each represent about 10 percent of the total high cost gas production while other areas (e.g., Wyoming, Colorado, Oklahoma, and Kansas) represent 27 percent.

3. A large proportion of the current high cost gas is purchased from contracts executed since the passage of NGPA in 1978. The volume distribution by contract period is:

   pre-1970 - 7%
   1971-1978 - 17%
   post 1978 - 76%

   Long-term gas purchase contracts were the predominant type of contract during the pre-1982 period. Prior to 1960, many contracts were effective for life of the reserves, and since that time contracts generally run 15 to 20 years, with a smaller number effective between 5 and 10 years in more recent years. Most contracts for OCS gas have 15 to 20 year terms, and all NGPA Section 102(b) contracts for purchases from new OCS leases are at least 15 years long, following Section 315 of the NGPA, and FERC Order 20, issued 8/2/79 (RM79-8).

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[1] About 25 percent of this OCS gas is classified as NGPA Section 102(b), production from new leases.

Because of the relative recentness of the contracts under which high cost gas is currently being purchased (i.e., since 1978), and the long term nature of these contracts, the majority of these high cost gas purchases will be effective until after 1990, as shown on Table 4 and depicted on the following chart. Only 13 percent of the high cost gas purchases are under contracts terminating prior to 1990, and 61 percent are under contracts terminating between 1990 and 1995, while the remainder (26 percent) terminate after 1995 or continue for life of the reserves. (Life contracts represent a relatively small share of the total, i.e., less than one percent).

Table 4

VOLUMES AND TERMINATION DATES OF HIGH COST GAS CONTRACTS (MMcf)

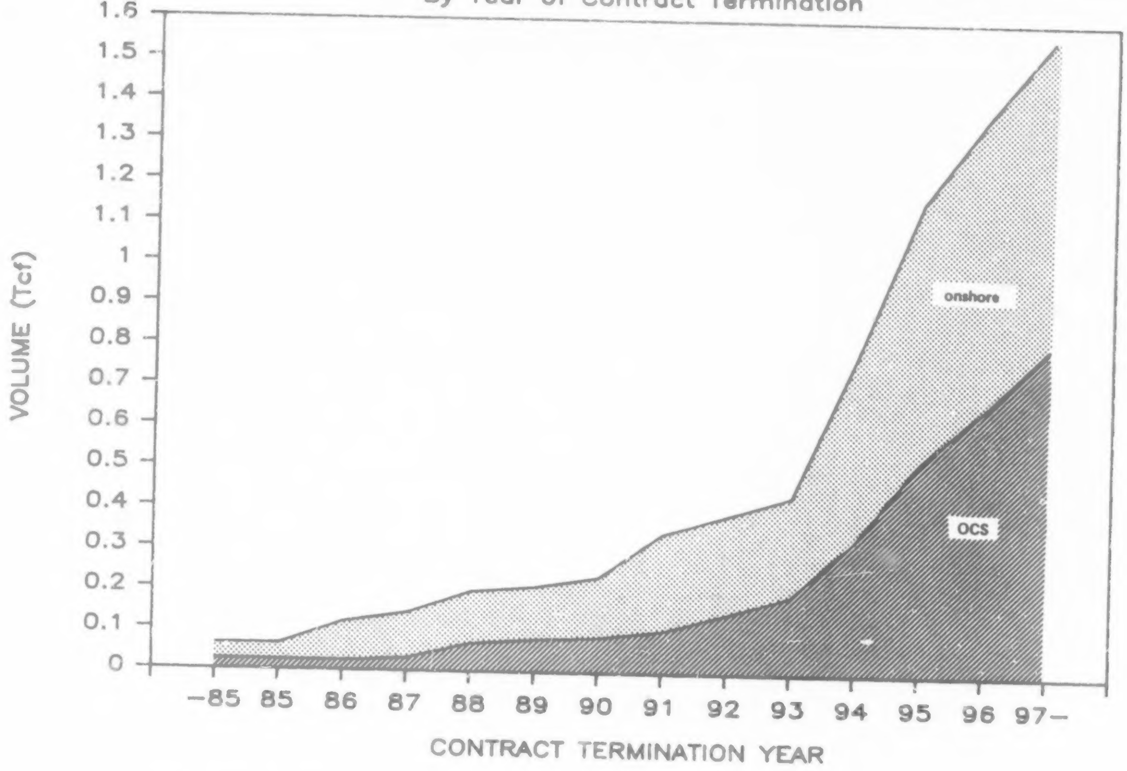
Contract Termination Date	OCS	LA	TX	Other	Total
Before 1985	24,002	17,806	13,120	8,278	63,206
1985	--	1,874	--	48	1,922
1986	1,239	16,244	6,521	30,886	54,890
1987	7,093	11,246	3,905	1,562	23,806
1988	37,586	1,653	4,099	11,014	54,352
1989	11,062	--	142	937	12,141
1990	6,497	214	--	18,118	24,829
1991	18,106	27,290	10,955	53,139	109,490
1992	41,835	--	1,093	2,343	45,271
1993	44,543	--	469	2,343	47,355
1994	139,071	14,369	67,892	123,759	345,091
1995	195,780	30,344	25,869	127,442	379,435
1996	130,520	27,377	9,077	41,863	208,837
After 1996 & Life	151,947	4,649	10,233	24,441	191,270
TOTAL	809,281	153,066	153,375	446,173	1,561,895

Source: Foster Associates, Inc.

Chart 2

CUMULATIVE GAS PURCHASES*

By Year of Contract Termination



*NGPA 102 and 107, high cost gas, and contracts executed before 1982

AGA
American Gas
Association

July 26, 1985

Natural Gas Production Capability - 1985/1986

In Brief.

Reduced consumption of natural gas from the 1975-81 average of 19.7 Tcf per year, coupled with nearly constant domestic gas delivery capability from 1980-1984, has led to the significant shutting in of natural gas production (often referred to as the gas "bubble"). Although gas demand has begun to recover, speculation continues on how large this excess capability is and how long it will last.

The purpose of this analysis is to examine gas production capability for 1985 and 1986 and to update our earlier estimates of the size of the gas bubble. The current analysis uses more recent data and a slightly modified methodology to update earlier A.G.A. estimates as well as make some evaluation for 1986. This assessment of the 1985 domestic unused production capability is consistent with the earlier work and shows a decrease to about 2.9 Tcf -- down from 3.2 Tcf in 1984. In 1986 this unused production capability is expected to continue to decrease to about 2.4 Tcf (see Figure 1). These estimates, like the earlier estimates, do not reflect the Canadian gas under contract but not being purchased.

Introduction.

Gas utility sales and total natural gas consumption declined significantly in 1982 and 1983 and rebounded in 1984. By 1983 U.S. natural gas consumption was 16.4 percent below the 1981 level. In 1984 sales increased by 4.6 percent over 1983. The economic recession and recovery, the very competitive pricing of oil products in some regions, weather and conservation each played a part in these variations in gas sales.

Definitions of Production Capability.

Many estimates have been published concerning the size of the "gas bubble". Readers of the popular literature about the gas industry are undoubtedly confused about the wide numerical range of these estimates. While many of the estimates are based on fundamentally different assumptions, the reader is often not alerted to the definitional differences in these estimates. Popular estimates generally fall into one of the following classes:

- evaluations of the severity of pipeline "take or pay" problems. The gas bubble is assumed to be directly proportional to the pipelines' take or pay exposure.

- attempts to measure the difficulty experienced by a producer in selling gas. These estimates may differ greatly depending on factors such as the season of the year, the volume of gas being sold, and the expected production rate.

- forecasts of total gas demand less supplies with fixed assumptions regarding the levels of gas imports.

- evaluations, such as this series published by A.G.A., which attempt to distinguish between what producing wells will produce (limited by demand) and what producing wells are capable of producing (under normal conditions).

These different studies have produced dissimilar results. Furthermore, each type of study must incorporate a number of assumptions which are, in themselves, speculative.

Methodology.

The methodology used in this analysis is based on the extrapolation of individual gas well production trends. With this technique, total U.S. non-associated gas production and the number of producing gas wells in a given year are used to calculate an average production per gas well. This value is compared to the estimate of gas well production capability which is the result of extrapolation of 1977-1979 production trends which show a decline of about 5 percent per year. This period reflects production per well statistics when there was no significant unused production capability. (The 1980-1985 data reflect a period when the decline in production per gas well was accelerated because of reduced demand.) The production capability per well, when multiplied by the number of producing wells, yields an estimate of total non-associated gas production capability between 1979-86. Estimates of associated-dissolved gas production (from oil wells) are based on recent production data as reported by EIA and are projected on the basis of the percentages of total production which is associated-dissolved gas. These data are adjusted from reported EIA statistics because EIA reports volumes including liquids (wet). In this study, the sum of the non-associated gas production and the associated-dissolved production is made equal to the total dry production as reported by EIA for years through 1983. After 1983, projections of production capability are estimated as the sum of non-associated gas production capability and associated-dissolved production.

The methodology used in earlier studies treated the oil well produced gas with the non-associated gas production. After several years of excess supplies, the production quotas and allowables are now quite different between gas produced from oil wells and that produced from gas wells. This fact necessitated a modification in the methodology which is intended to address this difference. Specifically, the associated-dissolved production capability is calculated from the assumed total production based on the ratios listed in Table 1.

Table 1 provides the statistical data necessary to develop historical estimates of non-associated gas production per well. The estimate for 1985 gas production is derived from the total gas production through March 1985 as reported by EIA in the Monthly Energy Review and is consistent with the six-month Gas Demand estimate published by A.G.A. in July 1985. This analysis assumes that domestic gas production in 1985 will be 16.85 Tcf.

The historical non-associated gas production in Table 1 has been derived from the EIA annual reserves reports and EIA Monthly Energy Review. The reserves reports are used to obtain ratios of non-associated gas production to total gas production. Producing gas well data are taken from published Natural Gas Annual and World Oil statistics.

Table 2 shows estimates of the non-associated gas production capability per well, the number of producing gas wells, the non-associated production capability and the associated-dissolved gas production. The difference between the capability to produce and actual production is the basis of the calculation of the unused production capability as shown in Table 3.

Maximum Production Capability.

The estimates developed here are intended to evaluate what production levels might be achieved with wells already drilled and attached to pipelines. Some additional capacity also exists in wells that are capable of gas production but have not been completed or are not connected to a pipeline. In addition, there are large volumes of gas behind the pipe[1] (gas not being produced because production from that well is presently coming from other depths) which are excluded from production capability. In both situations these volumes of gas represent a capability that is not utilized.

These estimates include only gas that comes from reservoirs currently capable of producing and connected to pipelines. A larger volume could be produced under different operating conditions, such as a very large unsatisfied demand for gas. The estimates in this analysis are based on the production capability if demand were only marginally higher than current levels.

Results.

This methodology shows that the unused production capability has increased significantly since 1979. The 1984 level of 3,205 Bcf is lower than the peak level indicated for 1983. This level is expected to continue to decline in 1985 and 1986 with the unused production capability decreasing to about 2,400 Bcf in 1986 as demand strengthens and increases in Canadian imports moderate.

Sensitivity of Results.

These results of this analysis through 1986 are generally compatible with the earlier analyses reported in the Gas Energy Review (February, 1983; August, 1983; February, 1984; July, 1984 and the "1985 Outlook"). "Bubble" estimates for 1985 and 1986 are, of course, extremely sensitive to the assumed levels of 1985-1986 consumption. In this study we have assumed that consumption will increase only slightly from 1984 to 1985 and 1986.

National Production Capability.

The methodology outlined above indicates that the projected total production capability through 1986 decreased only slightly since 1979. Decreasing production per gas well has been generally offset by the increase in the number of producing gas wells. This finding is controversial in that claims have been made of major losses in national production capability.[2] These two points of view can be examined by looking at what production has actually been demonstrated in recent years as shown in Table 4.

Table 4 is a tabulation of the daily production rates for the month of maximum production for six major gas producing states. The final two columns of the table show the ratios of the production in that state for 1984 (or January 1985) as compared to 1980 and 1983 as compared to 1981. The general conclusion is that while production levels are typically lower in 1983 and 1984, the capacity to produce gas nationally has been demonstrated at 93.4 percent of the 1980 level. In some states 1983 and 1984 peak month production levels were higher than the 1980 and 1981 levels. At worst, a decline of six to eight percent might be indicated. At best, there has been no loss in production capability at all. In 1984 many Texas wells experienced damage due to freezing weather which severely limited production at that time. Subsequently, there has been extensive speculation that the Texas gas production capability could have been permanently affected.[2] Table 4 statistics on Texas production do not support such speculation.

Another set of statistics on well production can be derived from the "Natural Gas Monthly" published by the EIA. These statistics provide projected production estimates which were submitted with NGPA well classification requests. These data are indicative of initial production forecasts for each reported NGPA classification category. Five complete years (1979-1983) and one partial year (1984 through February) of statistics do not exhibit any clear pattern of increasing or decreasing production per well for the totals. However, both Section 102 (new natural gas) and Section 107 (high cost gas) production per well have decreased rather sharply since 1979.

Gas Imports.

These results do not reflect the formidable deliverability from gas supplies of Canada and Mexico. For example, the Canadian National Energy Board (NEB) has already approved increased exports to the U.S. for 1985. As reported in the Gas Energy Review (January 1985), 769 Bcf of Canadian gas was actually imported in 1984; however, NEB analyses suggest that a 1.9 Tcf export capability probably exists.[3] About 1,000 Bcf could be delivered from Canada in 1985.

Mexico also has the capability to reinstitute the flow of gas to the U.S. In 1984 Mexico exported about 60 Bcf to the U.S.[4] If a need existed for this gas, deliverability from Mexico could be as much as 100 Bcf per year.

Conclusions.

Natural gas production in 1985 and 1986 will again be limited by the demand for natural gas. Estimates of production capability are highly susceptible to error; however, an unused production capability of about 2,900 Bcf probably exists in the lower 48 states now. This level will probably decrease to about 2,400 Bcf next year. When this capability is combined with the unused Canadian and Mexican capabilities, a current capacity (1985) to deliver an additional 3.9 Tcf exists beyond an estimated production level of 16.85 Tcf. This would represent about a 14 percent increase over 1984 consumption levels.

Footnotes

[1] "Behind the pipe" reserves are gas volumes which are known to exist in producing reservoirs but are at depths other than the zones currently being produced (usually shallower depths). When the strata that are being produced have been depleted, the well will be sealed at those production levels and production of the "behind the pipe" reserves will commence.

[2] Natural Gas Deliverability Study - Final Report, Interstate Oil Compact Commission, December 1984.

[3] Gas Energy Review, January, 1985.

[4] Gas Energy Review, August, 1984.

Table 1

PRODUCTION PER GAS WELL

Year	Total Gas Production in Bcf	Non-Associated Gas Production in Bcf	Ratio of Non-Associated Gas Produced to Total Gas Production	Producing Gas Wells	Annual Non-Associated Gas Production per Gas Well MMcf
1975	19,236	15,389	.800	132,095	116.5
1976	19,098	15,259	.799	137,542	110.9
1977	19,163	15,560	.812	147,658	105.4
1978	19,122	15,737	.823	157,454	99.9
1979	19,663	16,320	.830	169,891	96.1
1980	19,403	16,007	.825	182,004	87.9
1981	19,181	15,920	.830	198,839	80.1
1982	17,758	14,597	.822	210,753	69.3
1983	16,033	12,794	.798	221,952	57.6
1984	17,214	13,599	.790[3]	226,077[1]	60.2
1985	16,850 Est.	13,312[2]	.790[3]	230,077[4]	57.9
1986	17,200 Est.	13,588[2]	.790[3]	238,077[4]	57.1

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[1] "Number of Producing Gas Wells Increases", World Oil, February 15, 1985.

[2] Based on the total gas production estimates as shown in Column Two.

[3] The ratio of non-associated gas production has generally declined during the period of low demand. This trend was projected to continue through 1984 and then level out.

[4] Based on assumptions regarding the number of gas wells completed and abandoned in 1985 and in 1986. For 1985 it is assumed that 4,000 more wells are completed than are abandoned. For 1986, 8,000 more gas wells are assumed to be completed than gas wells abandoned. Representative figures for 1985 might be 12,000 gas wells completed and 8,000 wells abandoned and for 1986, 15,000 wells completed and 7,000 wells abandoned.

Sources: A.G.A. Reserves of Crude Oil, Natural Gas Liquids and Natural Gas in the United States and Canada as of December 31, 1979; EIA, Monthly Energy Review; EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves; EIA, Natural Gas Annual.

Table 2

ESTIMATES OF PRODUCTION CAPABILITY 1979-1985

Year	Non-Associated Production Capability per Gas Well[1]	Number of Producing Gas Wells	Non-Associated Production Capability in Bcf	Associated-Dissolved Production in Bcf[2]
1979	96.06 MMCF	169,891	16,320	3,343
1980	91.26 MMCF	182,004	16,610	3,396
1981	86.69 MMCF	198,839	17,237	3,261
1982	82.36 MMCF	210,753	17,358	3,161
1983	78.24 MMCF	221,952	17,366	3,239
1984	74.33 MMCF	226,077	16,804	3,615
1985	70.61 MMCF	230,077	16,246	3,538
1986	67.08 MMCf	238,077	15,970	3,612

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[1] The 1980-1986 estimates are based on a 5 percent per year decline from the production capability demonstrated in 1979 (when there was little or no unused production).

[2] These values are the implied associated-dissolved production based on data in Table 1; values for 1984-1986 are based on regression analysis of 1981-1983 data.

Table 3

PRODUCTION AND PRODUCTION CAPABILITY[1]
1979-1985
(in Bcf)

Year	Actual Production[2]	Production Capability[3]	Unused Production Capability
1979	19,663	19,663	0
1980	19,403	20,006	603
1981	19,181	20,498	1,317
1982	17,758	20,519	2,761
1983	16,033	20,605	4,572
1984	17,214	20,419	3,205
1985	16,850 Est.[4]	19,784	2,934
1986	17,200 Est.[4]	19,582	2,382

---

[1] Expanded from non-associated production capability using extrapolations of ratios established in Table 1 sources.

[2] EIA Monthly Energy Review, February 1985 data.

[3] This estimate is the sum of the non-associated production capability and the associated-dissolved production from Table 2.

[4] This estimate is consistent with the actual 1985 production through March. Production in 1986 is based on the assumption of a small increase in demand over the 1984 level and a leveling off of Canadian imports at about 1 Tcf.

NOTE: This methodology assumes that prior to 1980 there was no unused production capability.

Table 4

DEMONSTRATED NATURAL GAS PRODUCTION IN PEAK MONTHS

State	Daily Production Demonstrated in Peak Month*					Ratios	
	1980	1981	1982	1983	1984	1984/1980	1983/1981
Kansas	3,270	2,188	2,191	2,057	1,968	.602	.940
Louisiana	20,446	19,686	18,474	15,928	18,583	.909	.809
New Mexico	3,339	3,339	3,307	2,972	3,117[1]	.934	.890
Oklahoma	6,444	6,252	6,032	5,608	6,474	1.005	.897
Texas	20,143	19,511	19,013	17,483	18,331	.910	.896
Wyoming	1,308	1,345	1,378	1,509	1,533	1.172	1.122
U.S.	59,061	56,509	55,749	51,763	55,143	.934	.916

*in Bcf

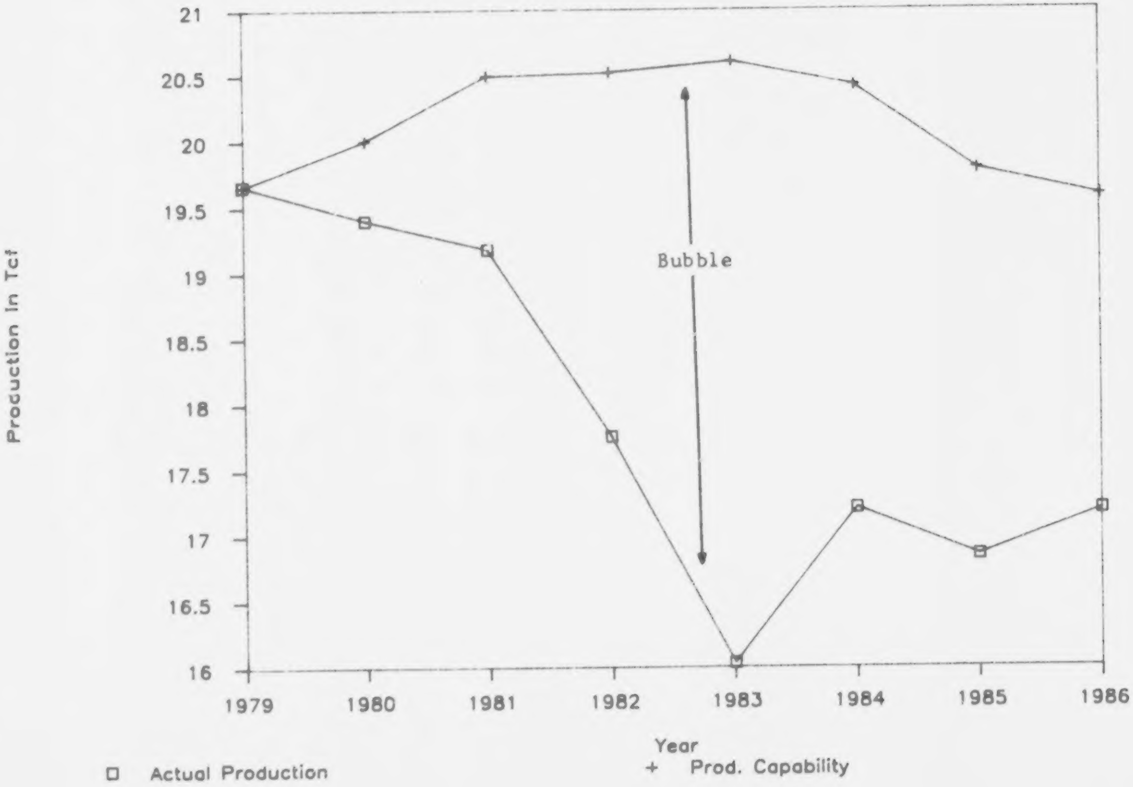
[1] This daily production was achieved in January 1985.

Source: EIA, Natural Gas Monthly.

Figure 1

Production Capability versus Production

1979 to 1986



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August 30, 1985

MEMORANDUM

TO: Howard Useem
Professional Staff Member

FROM: PEG

RE: Responses To Follow-Up Questions Posed By Senator Ford

The following responses are in follow-up to the questions posed by Senator Ford in connection with our appearance at the Subcommittee's July 11, 1985 Oversight Hearing on the current state of and the factors affecting the natural gas market.

QUESTIONS BY SEN. FORD FOR ALL WITNESSES APPEARING BEFORE THE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION ON JULY 11, 1985

1. This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?

Response to Question 1:

We believe the Commission has adequate legal power to provide for a range of "self-implementing," non-discriminatory transportation programs on interstate pipelines and, as a condition to access to federal programs, on local distribution companies. This is the primary action now required to protect the public interest during the current transition in natural gas markets. While we do not believe FERC has adequate legal authority to put into effect all elements of its current program as described in the NOPR of May 30, 1985 in Docket No. RM85-1-000, many of these proposals would be inconsistent with the public interest as discussed in our written and oral testimony to this Subcommittee, and PEG's written comments to the Commission which are attached hereto. In particular, PEG opposes adoption of Part D of the proposed rule, the block pricing proposal.

2. Would any witness oppose repealing incremental pricing and amending the Powerplant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?

Response to Question 2

We would support the repeal of incremental pricing and the amendment of the Powerplant and Industrial Fuel Use Act to repeal its demand constraints, and termination of all price and allocation controls on natural gas.

3. If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?

Response to Question 3:

If implemented as proposed, the NOPR could have a serious, negative impact on the price and availability of natural gas supplies to industrial consumers. An examination of Part D of the NOPR, the language of the NOPR and the history of federal regulation of wellhead prices supports this conclusion.

Part D, the regulations dealing with the trifurcation of gas costs into three blocks, is the device the Commission selected to create an entitlements program by transferring the "cushion" of certain categories of gas, those at $2.50 or less, into Block One. Block Two contains all other categories of gas, both regulated and deregulated.

This block pricing of gas results in drastic spreads in the average prices of Block One and Block Two on some pipelines, up to $3.50.

The past and current problems caused by the cushion of cheap, forever regulated gas will not be solved by merely transferring the cushion from pipelines to local distribution companies, which are subject to state, not federal regulation, and the creation of a new federal entitlements program. Under the Commission's proposal, another federally regulated entitlements program will arise, with the cushion being disproportionately allocated to some customers, mainly local distribution companies, without any conditions as to whether the benefits must be passed on to each and every consumer.

Our concern about the proposal's impact on gas supply arises from its artificial regulation of wellhead prices. The NOPR states the Commission's intent that the "second block would be priced higher than a pipeline's present WACOG, which includes old gas." NOPR at 44. Further, in discussing the new rate structure, the Commission states that "this three-part rate structure should serve to lower gas prices in the second block and act as a disincentive to imprudent pipeline gas purchasing practices." NOPR at 51. It thus appears that the Commission's proposed regulation of gas at the pipeline level is intended to reduce the price at the wellhead of both regulated and deregulated gas. This regulation of the price of all gas will not occur as a result of the free market, but rather as the result of federal regulation. In the past, federal regulations affecting gas prices at the wellhead have led to supply curtailments.

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

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WM C. ANDERSON
VICE PRESIDENT
POLITICAL AND LEGISLATIVE
RELATIONS

August 26, 1985

Mr. Howard Useem
Committee on Energy and
Natural Resources
U.S. Senate
360 Dirksen Senate Office Building
Washington, D.C. 20510

Dear Howard,

Attached are the responses to follow-up questions of IPAA witness Ray Potts from the July 11 hearings.

At the time we appeared, we asked that our FERC filing on RM-85-1 be included in the hearing record. A copy of it is enclosed also.

Let me know if we can be of further assistance.

Sincerely,

Bill

Wm. C. Anderson

Rockefeller Question

As we discussed during the hearing, please provide a legal opinion on FERC's authority to include stripper wells in Block One as proposed in the NOPR. Please pay particular attention to how doing so would affect the specific intent of Congress to encourage stripper well production, as expressed in Sec. 108 of the Natural Gas Policy Act.

Answer: As the Senators know, private legal opinions do not generally have a great deal of standing in the legal/legislative process. We would like to suggest, therefore, several principles which we believe must be considered.

First, we believe the legal question centers on whether or not FERC has the authority to establish block pricing to enforce it. We question the concept of reserving certain gas for certain historic users. Curtailment priorities have established the Commission's authority to reserve gas for classes of users. However, all users fitting a priority use have been covered, not just those who have an historic base. In addition, those priorities have stood for gas, not for a specific body of gas which might have preferential pricing from a user's point of view.

If FERC has the authority to establish block pricing, then we see no legal basis for including or excluding any category of production from any block. It must be remembered that NGPA ceiling prices established by law were just that -- ceiling prices, not support prices. While inclusion or exclusion of certain gas from one block or another could have a serious impact on demand for that gas, we don't see how Congress' designation of that gas for higher ceiling prices in and of itself automatically dictates that those higher prices are guaranteed.

Finally, we believe the question which FERC must consider is whether or not its actions are consistent with or counter to the spirit of the NGPA. If Congress designated certain categories of gas as being eligible for special incentives if market conditions allowed such incentives, then we feel the Commission is on shaky moral and ethical ground if it takes action which would have an absolute reverse impact on that same gas. It may no longer be possible to sustain higher than market prices for stripper and high cost gas, for example, but at a minimum we believe that the worst case for that gas should be an equal spot at the "starting line" with all other gas. It would appear that the FERC proposal would handicap that gas to a less than equal status.

Thus, if FERC has the authority to create block pricing, then it probably has the authority to put whatever gas it chooses into any block. But as is the case so often, just because authority exists, it requires prudence and fairness on the part of those exercising it.

Questions by Senator Ford

1. This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?

Answer: From our point of view, it is difficult to determine just what authority the FERC has and does not have post-NGPA and it seems that the D.C. Court changes what we think along those lines on a weekly basis.

We believe that if there is a need for additional authority, it is in the area of transportation. We don't believe any entity in the natural gas industry, particularly those which have been granted monopoly positions by regualtory bodies during periods of total regulation, should be allowed to use those monopoly powers to thwart competition. If producers are going to be subject to full competition from alternate fuels and from other packages of natural gas, and if consumers are going to be allowed to shop for the best energy deal, then pipelines and distributors cannot be allowed to refuse to transport gas for any reason other than a proven lack of capacity. It may be that Congress will have to state that proposition in legislative terms.

2. Would any witness oppose repealing incremental pricing and amending the Powerplant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?

No. However, such repeal in itself may not be the answer. For example, unless open transportation is assured, it might be that any new markets created by repeal of FUA would end up with imported gas. In the future, any new market for gas should be available to those who can deliver the gas at the most favorable rates under the most favorable conditions to the purchaser, not for the benefit of the transporter as in the past.

3. If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?

In the short run, those high priority users on pipeline systems with large volumes of old gas should see their gas costs decrease -- provided pipelines and distribution companies don't just use those lower prices to increase their margins. That would be in the short run. However, in the longer run, it will increase consumer prices as the result of decreased production and potential future shortages. Every past move by government to suppress energy prices has led to shortage induced price increases at later dates. We don't believe this would be any different.

As we see the current FERC proposal, past producer incentives will be eliminated and in some cases disincentives to production will be substituted. The cumulative effect of several years of reduced drilling for new gas supplies will lead to shortages and subsequent higher prices. The challenge to FERC and Congress should be to clear away unnecessary regulations in all segments of the gas industry so the market can work.

STATEMENT OF

INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

AND

AMERICAN ASSOCIATION OF PETROLEUM LANDMEN
ARKANSAS ROYALTY MEMBERSHIP
CALIFORNIA INDEPENDENT PRODUCERS ASSOCIATION
COASTAL OIL AND GAS ASSOCIATION
EASTERN KANSAS OIL AND GAS ASSOCIATION, INC.
EAST TEXAS PRODUCERS AND ROYALTY OWNERS ASSOCIATION
ENERGY CONSUMERS AND PRODUCERS ASSOCIATION
GEORGIA OIL AND GAS ASSOCIATION
ILLINOIS OIL AND GAS ASSOCIATION
INDEPENDENT OIL AND GAS ASSOCIATION OF NEW YORK
INDEPENDENT OIL AND GAS ASSOCIATION OF WEST VIRGINIA
INDEPENDENT OIL PRODUCERS TRI-STATE, INC.
INDEPENDENT PETROLEUM ASSOCIATION OF MOUNTAIN STATES
INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO
INDIANA OIL AND GAS ASSOCIATION
INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS
KANSAS INDEPENDENT OIL AND GAS ASSOCIATION
KENTUCKY OIL AND GAS ASSOCIATION
LIAISON COMMITTEE OF COOPERATING OIL AND GAS ASSOCIATIONS
LOUISIANA LANDOWNERS ASSOCIATION INC.
LOUISIANA ASSOCIATION OF INDEPENDENT PRODUCERS AND ROYALTY OWNERS
MICHIGAN OIL AND GAS ASSOCIATION
NATIONAL STRIPPER WELL ASSOCIATION
NEW YORK STATE OIL PRODUCERS ASSOCIATION
NORTH TEXAS OIL AND GAS ASSOCIATION
OHIO OIL AND GAS ASSOCIATION
OKLAHOMA INDEPENDENT PETROLEUM ASSOCIATION
ORANGE COUNTY PETROLEUM ASSOCIATION
PANHANDLE PRODUCERS AND ROYALTY OWNERS ASSOCIATION
PENNSYLVANIA GRADE CRUDE OIL ASSOCIATION
PENNSYLVANIA OIL AND GAS ASSOCIATION
PERMIAN BASIN PETROLEUM ASSOCIATION
ROYALTY OWNERS AND INDEPENDENT OIL AND GAS PRODUCERS ASSOCIATION OF ARKANSAS
TENNESSEE OIL AND GAS ASSOCIATION
TEXAS INDEPENDENT PRODUCERS AND ROYALTY OWNERS ASSOCIATION
VIRGINIA OIL AND GAS ASSOCIATION
WEST CENTRAL TEXAS OIL AND GAS ASSOCIATION

FEDERAL ENERGY REGULATORY COMMISSION

RE: RM 85-1-000

JULY 15, 1985

Executive Summary

The Independent Petroleum Association of America commends the Commission for its willingness to confront a very complex problem in a comprehensive way.

While we realize the Commission must try to balance the perceived needs of all segments of the natural gas industry, as producers we must focus on those aspects affecting our ability to maintain adequate supplies of gas now and in the years to come.

The producing sector, while presently in a position of excess deliverability, is experiencing a severe downturn. Wellhead revenues are declining, prices of some categories of gas are in severe decline, wellhead completions are down and the active drilling rig activity is half what it was 3-4 years ago.

Because of lead times involved, it is today's activity which will determine what levels of supply are available in the late 1980's and early 1990's. If today's level of activity is not enough reason for concern, add to that potential adverse tax legislation now pending and continually falling alternate fuel prices, and one has to take seriously even the smallest negative impacts of this proposed rulemaking on the producing sector if you have any concern at all for adequate supplies in the near and long term future.

On the following pages of our response to the rulemaking we make some rather specific recommendations designed to reduce or eliminate negative wellhead impacts. We hope the Commission gives them careful study and we thank you for this opportunity to respond. In doing so, at least when the day comes in the not too distant future that we are faced with shortages and curtailments, it can't be said that producers didn't warn the Commission and the public of what was coming.

Thank you.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Regulation of Natural Gas)
Pipeline after Partial Decontrol)
Docket No. RM85-1-000

COMMENTS OF THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

The Independent Petroleum Association of America and the other state and regional oil and gas associations listed on the cover sheet offer these comments in response to the Notice of Proposed Rulemaking issued on May 30, 1985 by the Federal Energy Regulatory Commission. IPAA and the other listed associations represent the more than 15,000 independent explorer-producers of domestic crude oil and natural gas.

In that independents drill 89 percent of all wildcat wells, 86 percent of all wells and find 60 percent of all domestic natural gas reserves, they have a vital interest in a healthy, expanding natural gas producing, transportation and marketing industry. With that in mind, it is obvious that independents have valid reasons to be concerned about any legislative or regulatory actions confronting the natural gas industry.

All correspondence and comments regarding this matter should be addressed to:

Lloyd N. Unsell, Executive Vice President
Independent Petroleum Association of America
1101 16th Street, N.W.
Washington, D.C. 20036

Introduction

At the outset, we commend the Commission for moving forward to try to address some of the problems which it has identified as developing in a new era of natural gas pricing and marketing. While it may appear later in this filing that we are critical of some of the Commission's proposals, let that criticism in no way diminish the fact that it has been bold enough to move forward where others have feared to tread -- rightly or wrongly.

Probably no industry in America has been impacted by more politically motivated economic tinkering over the past 30 years as has ours. From the Phillips Supreme Court decision in 1954, to major Federal Power Commission interpretations of that decision in the 1960's to the passage of the Natural Gas Policy Act in 1978, natural gas producers have seen their economic fortunes tied more to political decisions than to sound supply demand conditions.

While that long history is behind us now and we find ourselves with more than half of all natural gas decontrolled as to price at the wellhead, we cannot look at today's problems without recognizing certain mind-sets which developed over those past years of rigid regulations.

Because of long years of low wellhead price controls, the market for natural gas in the interstate market grew on one basis -- low prices. By the mid 1970's total annual production based on those price induced markets reached 22 Tcf per year.

However, about that same time, the same low prices which stimulated demand so well, worked to discourage drilling and reserves and supplies available to the interstate market began to decline. This led to the need to curtail deliveries to low priority users and to find ways to try to stimulate production.

Because higher uncontrolled prices had worked well to increase supplies for the intrastate markets of the Southwest, Congress took action to try to help the interstate markets by passing the Natural Gas Policy Act of 1978.

It was designed to increase supplies to interstate market high priority users in three basic ways. First, it opened up the previously closed interstate markets to uncontrolled supplies in the intrastate market. This brought an immediate end to curtailments. Secondly, it moved to dampen high volume demand by limiting and prohibiting the construction of major new industrial and utility facilities burning gas as a fuel. And finally, using the volumes of old, low priced gas remaining under wellhead controls, it proposed to pay producers incentive prices to increase production.

All of these actions seemed logical to many, however, all had a common flaw -- they denied the existance of basic laws of supply and demand and the impact on markets of alternate fuel sources and the market pricing of those sources. The fact that market prices for those alternative fuels began a steady decline after 1981 while NGPA acted to steadily increase average gas prices, only exaggerated the problem.

Thus, as we approached January 1, 1985, the "drop dead" date for much of NGPA's pricing features, we found wellhead prices of natural gas ranging from 28 cents on the low end to nearly $10 on the high end. But more importantly, we had seen average wellhead prices of gas increase by 30 percent between 1981 and 1984 while alternate liquid fuel prices had dropped by 20 percent.

If that disparity was not enough to make gas less competitive, transporters took this occasion to more than double their average sales prices. While average producer prices increased by 65 cents per mcf between 1981 and 1985, prices to industrial users went up by $1.12 mcf, to electric utilities by 80 cents and to residential users the increase was $1.77.

It then is not surprising to see demand for gas dropping, resulting in a surplus or "bubble" at the wellhead.

Producers long have hoped that legislative solutions to these problems could be achieved and we worked for 18 months during 1983 and 1984 with Members of both Houses of Congress to achieve balanced, workable legislative solutions, and failed.

To date, this Congress has shown little enthusiasm for moving forward, so at least the Commission's action should indicate to all involved that the status quo post-NGPA probably serves no one well. Whether or not the Commission can achieve a workable concensus which solves more problems then it creates remains to be seen and represents the purpose and objective of these proceedings.

Transportation

In our comments to the Commission's earlier Notices of inquiry, we strongly advocated the establishment of a new system of non-discriminatory contract carriage for natural gas producers and consumers.

We commend the Commission for its transportation initiatives in this docket. This proposal could, we believe use some "fine tuning" and clarification. In those matters, rather than contributing to repetition, we would direct Commission attention to the filing of the Association for Natural Gas Equal Access. IPAA and the other producer associations have worked closely over the years with NGEA and we share common objectives of that group, most of whose members also are members of our associations.

There are, however, a couple of points related to transportation which we would like to emphasize and some unanswered questions we would like to pose to the Commission.

First, we are concerned about the practical operation of provisions which allow firm sales contract customers of pipelines to opt out of supply contracts over a four-year period.

While we clearly understand the objective of this provision, we question the operation of it as a practical matter. With the Commission's decision last year to render minimum - bill provisions of such contracts inoperable, there appears to be little reason for local distribution companies to excercise this option. As a practical matter, volumes are not now being taken under these contracts and the only penalty LDC's are paying for keeping such contracts is a modest demand charge.

Recognizing the swings we have gone through over the past decade, we doubt that LDC's would give up such contracts, but instead would pay the small charge for keeping them and go out and shop for cheaper gas, using carriage provisions of this rulemaking to buy gas but at the same time reserving pipeline capacity on the same system "just in case" supplies tighten again and they find the spot market moves above firm sales contracts they hold.

It seems to us that this gives LDC's the "best of both worlds" in both shopping for gas and reserving pipeline capacity. We doubt that potential new industrial or distribution customers on such a system would be able to capture much firm pipeline capacity due to what we would call "phantom" capacity utilization.

We would urge the Commission to rethink this portion of the proposal to find new answers to this problem. Is it not true that a part of this problem is the so-called service obligation of the pipelines to LDC's and their high priority customers? Shouldn't the Commission consider procedures by which capacity reserved for such service obligations expired if not used by the firm contract customer during some peroid of time?

A second point we would emphasize is the role of the LDC in performing services under new transportation arrangements. We have heard it said that the Commission does not have jurisdiction over LDC's and therefore is reluctant to "encourage" them to be integrated into the non-discriminatory transportation provision of this rulemaking.

However, that did not stop the Commission from using it's "carrot/stick" approach on intrastate pipelines over which it has no jurisdiction.

We believe this rulemaking is loaded with benefits for LDC's and virtually no costs. Is it not reasonable that as a minimum price for receiving the benefits of such things as fully non-discriminatory pipeline transportation and take-or-pay settlements, that LDC's avail their facilities to transport direct sales gas beyond city gates? If the Commission believes it has the authority to provide for the breaking of a contract by a non-jurisdictional entity with a jurisdictional entity, couldn't that same authority require certain performance in return for that action?

Take or Pay

We are somewhat intrigued by the take-or-pay relief provision contained in the proposed rulemaking.

As we see it, the Commission is not trying to address already accrued take-or-pay liabilities, only prospective ones under certain contracts.

In informal discussions with Commission staff, it has been pointed out that producers may not be too interested in forever giving up all take-or-pay rights to a body of gas in a renegotiation setting. The reponse has been that such waiver applies only to the contract in question, that a new contract covering that same gas could contain take-or-pay up to 75 percent of volumes.

We are somewhat bewildered by the reasoning behind this apparently cumbersome excerise and hope the Commission makes further clarification if it finally adopts this provision.

We would like to address this entire section by way of a little background.

First, it is assumed by most people in Washington that take-or-pay provisions of producer contracts in and of themselves are a problem. We believe that is a very flawed assumption.

The problem associated with take-or-pay comes when linked to higher than average prices. To make our point, for example, we have heard of no pipeline purchasers having "take-or-pay problems" with a $2 gas contract.

Because independent oil and natural gas producers tend to be smaller producers, they do not have very strong leverage positions in the market place, particularly in today's market with its apparent excess deliverability capacity. Therefore, it has been these smaller producers who have become the early targets of "voluntary" contract renegotiation.

Because they had very little leverage and often found immediate cash flow needs crucial, they have been prime targets for market out threats and similar actions. Many small producers have settled quickly with pipelines in obvious cases of contract abrogation which may have been won in court but which would have been lost to economics in the process. Finding themselves in this tenuous position, most small producers have negotiated away take-or-pay rights in return for trying to hold onto price.

Having already given up their take-or-pay rights, now they see this rulemaking as a double edged sword. Through the block pricing scheme, they see their prices being driven down and at the same time an offer to "buy out" their take-or-pay rights which they already have given up free of charge.

So who might this provision effect most in the producer community? The answer is the large, highly leveraged producers, who have had the cash reserves to win court cases and hold onto both take-or-pay and high prices. The Commission is now proposing a "buy-out" for that which the small producer has already given away.

Recognizing the linkage between take-or-pay and price, we recommend that if the commission includes in it's final order a "buy-out" for take-or-pay, that it also include a "buy-out" of price provisions of contracts.

We are not sure how the market will absorb any "buy outs" and whether or not as a matter of fact they will work, but we believe fairness dictates that all producers have an opportunity to recover some costs for giving up market rights in the name of "leveling the playing field".

Block Pricing

Again, we commend the Commission for unbundling rates and setting transportation, storage, etc., costs aside, separate from commodity costs. Hopefully this will send clearer price signals the burnertip.

Having commended block 3, we must voice strong reservation as to the philosophy behind blocks 1 & 2.

We recognize that this is the Commission's attempt to deal with the alleged distortion which arise between pipelines owning more or less reserves of old, forever regulated gas.

Producers repeatedly have called upon Congress to establish an orderly means of decontroling the wellhead prices of this gas. We still believe that is the most sensible solution to the "cushion" problem.

But Congress has not acted, so in our comments on the earlier NOI we recommended that the Commission set in motion a new national rate proceeding to raise the price of this gas to levels more reflective of its replacement cost. Commission clearly has that authority under the Natural Gas Act.

We still believe that is a better answer -- for two basic reasons. First, it would reduce and eliminate the distortion which occur between burnertip prices paid by competing users of different pipelines -- a distortion which should be unacceptable in this populist era of "fairness". Secondly, it would tend to "level the playing field", but would leave the revenues of that process in the hands of producers -- the only sector of the natural gas industry which has the responsibility and the expertise to bring on future supplies of natural gas.

We believe it is ironic that the Commission has decided to transfer the economic rents of old gas to historic users at this time. One cannot pick up a newspaper today without reading one or more articles on the "crime" of federal deficits in borrowing from future generations to satisfy today's desires. Neither can one talk long with environmentalists without the arguement of preservation for the future becoming the central theme of discussion.

Yet the Commission is ignoring the future in its creation of block 1. It is saying that cheap gas is reserved for historic customers without any consideration for the actual cost of supplies for future generations of users, much less the hidden cost of lost supplies as a result of the diversion of dollars from producers to consumers. We believe this concept is unfair, unneeded and short sighted and urge the Commission to give serious thought to moving away from it as proposed in this docket.

Having said this, we realize that once a so-called "new, bold, concept" gets committed to writing, it tends to have a life of its own, and the tendency of the Commission will be to try to work within the framework of block pricing -- right or wrong. Therefore, we will suggest for Commission consideration some ideas for positive modification within the framework of the proposal.

First, we would ask the Commission why it has decided to follow this method, certainly one which will be challenged in the courts, when it has existing legislative authority on the books to accomplish much the same result -- as specifically outlined by Congress. We are speaking of Title II of the NGPA -- known commonly as incremental pricing.

Commission should know that IPAA does not support incremental pricing as written. Neither do many others, particularly some of our best customers in the industrial and process use categories. But neither are we and they all that warm to this proposal.

We point to NGPA Title II only to make some points as to how the current proposal falls short of what Congress intended in this area since there are so many similarities between Title II and the Commission's proposal.

Both appear to have the objective of awarding economic rents of certain gas supplies to one class of users at the expense of another class. In doing so, both would not only deny those rents to producers but would work to drive down the wellhead value of new supplies. Both would seem to perpetuate competitive distortions as between low cushion and high cushion pipelines and their customers. Others probably could think of other similarities.

We do not agree with those who suggest it was Congress' intent to capture all economic rents for special classes of users. If one carefully reviews the NGPA and the philosophy behind it, it clearly was the intent of Congress to create incentive categories of gas and in some cases sustain those incentives. Where else than the gas proposed for block 1 were those incentives supposed to arise absent expanding demand and rising alternate fuel prices?

If one accepts the premise that Congress did intend new drilling incentives, did it intend for those incentives to end automatically on all post-1978 gas on January 1, 1985, or only on those wells drilled after January 1, 1985? Does anyone see in NGPA language that it was the intent of Congress to lure producers into drilling wells with an incentive which was to be taken away after the investment was made and the action taken? Probably more importantly, was that the premise on which producer and pipeline arrangements were drawn under NGPA? If it was generally conceded that NGPA incentives were to be neutralized come January 1, 1985, why were contracts written as they were?

No, we believe it was intended that the "new day" after January 1, 1985 would be for wells drilled after that date. Why else would NGPA era new gas not had deescalator clauses if producers and purchasers had understood the incentive was to end automatically on January 1, 1985?

Therefore, we beleive there is justification for placing all pre-January 1, 1985 gas in block 1 if the block 1 concept is to be retained. That would tend to make good on whatever is left of the "promise of NGPA", while telling current drillers "your'e on your own, what you see is what you get".

We know this probably is more than the Commission might consider, even though we believe it would have a sound basis for doing so. If Commission is not willing to go this far, why has it decided to include in block 1 only old forever regulated categories of gas? Why not all forever regulated gas if the purpose is to let consumers know the true cost of regulated gas?

As we can best calculate from EIA data, the current price of block 1 gas as is now proposed would be about $1.53 per Mcf. Using that same data, that block 1 price would rise to $2.28 per Mcf if all forever regulated categories were included. Would that be unreasonable? Again, not according to Congress. Commission's own figures published for May places the Title II threshold price for incremental pricing at $2.39 per Mcf, an indication that Congress didn't ask that economic rents be shifted at $2.28, much less $1.53.

If the Commission selected the "all forever regulated block 1" theory, another serious problem would be eased -- that of protecting reservoir rights of owners of 103 wells drilled under 104 contracts. If the Commission holds to its current proposal, serious problems will arise relating to the sharing of production allowables between different category wells in the same field as well as the actual physical drainage over time of one producer's gas by another.

If the Commission still does not buy our arguements heretofore set forth, let us make one final appeal for the inclusion of an absolute minimum of three elements for inclusion in block 1 -- 108 stripper gas, 107 high cost/tight sands gas, and all dollars attributed to take-or-pay/contract "buy outs" previously addressed.

First, Section 108 was created as a specially legislated category, singled out for special incentives by Congress. We feel the Commission is bound to honor that mandate. Because of the marginal nature of these wells, we are afraid that if they are thrown into block 2, not only will Congressional intent be ignored, but much of this gas will be lost, shut in, and prematurely abandoned.

That would be a shameful waste of a recoverable resource in the name of regulatory reform. Again, sighting Title II, we believe Congressional intent is strong for continued incentives for stripper well gas in that it was provided with a higher threshold for incremental pricing. In May, according to your published data, that threshold is $3.96 per Mcf, not that far below EIA's reported average price of stripper gas in May of $4.28.

Secondly, we believe Section 107 gas should be sheltered in block 1. By its common name, "high cost gas", it is accepted that normal gas economics were not enough to justify its production. While volumes are not that great, and prices of this gas is declining steadily, we believe Congress' intent is clear for 107 gas which was given special treatment under Title II. According to EIA, the May average for 107 gas had dropped to $4.76 per Mcf, well below the $7.21 legislated incremental pricing threshold for that gas for the same month.

Finally, as a minimum addition to block 1, should be every dollar of take-or-pay/contract "buy outs". The so-called "sins" of these now undesireable contracts were committed in behalf of those who are covered by the block 1 entitlement and they should pay for the remedy. If, as most agree, the need in the long run is for more new customers of gas, why should we try to force new customers to pay for problems created in behalf of an already highly favored class of customers?

Conclusion

There are those who suggest that in a number of areas the Commission has gone beyond its authority and that the courts will say so. We will leave that debate to the lawyers, because we have found that no one can predict for sure how such debates will resolve themselves until they occur.

We do, however, want to leave you with a warning about future gas supplies. Because we appear to be operating within a climate of surplus deliverability, very few people are worrying today about short supplies and curtailment -- only about prices. Let us remind Commission that that was the same attitude we ran into in the late 1960's and early 1970's. When curtailments are with us, it's too late to worry about what it takes to assure supply.

A signal of where we could be headed is found in today's drilling statistics. Today's excess supplies can be attributed to drilling activity 3-5 years ago. In 1981, average daily rig activity stood at 3,970 active rigs; in 1982, 3,105. By 1984 that number had dropped to 2,428 and for 1985 we are averaging much below that level. Shortages in the 1970's came after several years of average rig activity below 2,000 active rigs. Does that tell us where we might be headed by the end of the decade?

Producers are prepared to make decisions based on market conditions. But action such as block pricing designed to beat down producer revenues, will most certainly result in further reductions in drilling for future needs. Add this potential action to threats of new tax burdens and continually falling world energy prices, and all we can say is "be careful," because what is done today, will be viewed closely for years to come.

We would like to close by paraphasing a comment made by former Commissioner Rush Moody back in the 1970's. He said that "when an architecturally flawed building collapes, rarely does it fall on the architect who was responsible for its bad design".

The same is true of the designers of regulations, and we hope the Commission will keep that in mind during its deliberations.

In any event, when curtailments return, and they will if we don't take action now to prevent their return, please don't say as was said to us in the 1970's, "why didn't you warn us ?" We are warning the Commission, that while low prices are nice, on a cold day consumers won't get much satisfaction out of admiring their low bills. Instead, they'll say, "why didn't somebody tell us?"

tfi

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FORD B. WEST
Vice President
Legislative Affairs

August 16, 1985

Mr. Howard Useem
Professional Staff Member
Committee on Energy and
  Natural Resources
United States Senate
Washington, D.C. 20510

Dear Mr. Useem:

Attached are the responses of The Fertilizer Institute to the follow-up questions transmitted with your memorandum of August 12, 1985.

If you require additional information, please feel free to contact us.

Sincerely,

Ford B. West

Ford B. West

FBW/cp
Enclosure

RESPONSE OF THE FERTILIZER INSTITUTE TO THE QUESTIONS OF SENATOR FORD

Q-1. This is an oversight hearing. But we are a legislative Committee. Several of you have commented that you believe FERC has gone beyond its statutory authority in the Notice of Proposed Rulemaking. My general question is this: Does FERC need any new statutory authority to enable it to protect the public interest during this transitional time in the natural gas industry?

A. The Fertilizer Institute (TFI) has filed comments with the FERC in general support of the transportation and optional certificate portions of the Notice of Proposed Rulemaking in Docket No. RM85-1-000. With respect to the application of the proposed regulations to interstate pipelines, it is TFI's position that the FERC has the requisite legislative authority to implement its proposal and protect the public interest. Nevertheless, TFI has also supported contract carriage legislation which would require interstate pipelines with available capacity to transport natural gas for end-users and distribution companies.

Q.-2. Would any witness oppose repealing incremental pricing and amending the Powerplant and Industrial Fuel Use Act to repeal its demand constraints on natural gas use?

A. TFI has not opposed repeal of incremental pricing or elimination of the demand restraints in the Powerplant and Industrial Fuel Use Act.

Q.-3. If implemented as proposed, how would the NOPR affect natural gas supplies? How would it affect prices paid by consumers for natural gas?

A. Implementation of the transportation and optional certificate aspects of the NOPR would promote competition in all segments of the gas industry. Competition provides the best incentive for an adequate gas supply at the lowest price.

APPENDIX II

Additional Material Submitted for the Record

STATEMENT OF THE AMERICAN PAPER INSTITUTE
to the
SENATE SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
on
NATURAL GAS

July 23, 1985

The American Paper Institute (API), the national trade association of the pulp, paper and paperboard industry, appreciates the opportunity to share its views with the Senate Subcommittee on Energy Regulation and Conservation in conjunction with its oversight hearings on natural gas markets.

API's members are major industrial users of natural gas. In 1984, for example, they consumed approximately 326 billion cubic feet of natural gas. This makes the pulp, paper and paperboard industry the sixth largest consumer of natural gas among manufacturing industries.

The pulp, paper and paperboard manufacturing process is highly energy-intensive. The delivered price of natural gas is a substantial cost component in the pulp, paper and paperboard manufacturing process. API's members therefore are vitally interested in efforts to increase the availability and access to less expensive natural gas supplies.

The paper industry supports the current efforts of the Federal Energy Regulatory Commission (FERC) to revise and amend its natural gas regulations to bring a large degree of rationality and competitiveness to the nation's natural gas markets.* FERC should be commended for its timely effort to improve access to the nation's natural gas supplies.

The paper industry generally supports the Commission's proposed regulations--especially the non-discriminatory transportation programs. API has urged the Commission, however, to require participating pipelines to provide interruptible as well as firm transportation service. Gas producers, pipelines and consumers all stand to gain from this broader transportation program. API has also urged the Commission to have its new regulations in place as soon as possible before November 1, 1985, since the Commission's existing special marketing and blanket certificate programs will expire on that date. Any interruption in the FERC's programs authorizing transportation of self-help gas would have serious ramifications for gas consumers in general and the paper industry in particular.

API has supported FERC's proposed "safe harbor" presumption of prudence as to certain take-or-pay settlements between pipelines and producers. The take-or-pay issue is a main obstacle affecting the willingness of interstate pipelines to open access to their transportation service.

API opposes FERC's proposal of a three block rate structure for the pipelines' purchased gas costs. The proposal conflicts with the Natural Gas Act and the Natural Gas Policy Act, would unlawfully authorize certain gas to be marginally priced, and would inappropriately create instability and unpredictability in natural gas rates. API supports rolled-in pricing of natural gas until total decontrol of wellhead natural gas prices is federal law.

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* Comments were filed by API with FERC on February 4, March 11 and July 15, 1985, generally supporting FERC's proposals.

In light of the fact that legislation decontrolling natural gas and opening up natural gas transportation has been difficult to achieve in the last few years, API hopes that members of Congress will support FERC's current natural gas efforts as the primary means of providing a free market orientation in the sale and purchase of natural gas.

UNITED STATES OF AMERICA
BEFORE THE
SENATE SUBCOMMITTEE ON ENERGY
REGULATION AND CONSERVATION

STATEMENT OF ANR PIPELINE COMPANY

This subcommittee held hearings on July 11, 1985 on a proposed rulemaking by the Federal Energy Regulatory Commission (FERC) which would radically change the way natural gas pipelines are regulated. Permission was given for the submission of written statements to be included in the record, if filed within thirty days. ANR Pipeline Company (ANR) therefore requests that this statement be made a part of this proceeding.

ANR is a major interstate gas pipeline company regulated by the FERC, with 11,900 miles of pipeline and more than one million installed horsepower of compression. This system extends from the Louisiana/Texas Gulf Coast and the Texas/Oklahoma Panhandle gas fields to ANR's midwestern service area. ANR purchases gas from over 1,900 gas producers under more than 2,800 contracts, as well as from other sources. Additionally, ANR operates 15 gas storage fields capable of delivering up to 2 billion cubic feet per day to meet peak demand. Gas is sold by ANR to 50 gas distribution customers in nine states, with the vast majority being sold in Michigan and Wisconsin. ANR has filed extensive comments with the FERC pointing out the many defects in its proposal. As a party principally affected by this rulemaking ANR is vitally concerned about its outcome and appreciates the opportunity to express its views to this subcommittee.

This proposal, called a "Magna Carta" for the natural gas industry by one FERC Commissioner, involves a realignment of the traditional rolls of gas producers, pipelines and consumers. The FERC should be commended for its concern over the present problems facing the gas industry. Unfortunately, however, its proposed solutions are based on a theoretical view of the operation of gas pipelines and producers. The proposal, therefore, is highly impractical and, if implemented, would actually cause higher consumer prices, shortages of gas, and general chaos in the industry.

Briefly, the problem being addressed by the FERC is that falling gas prices, brought about by the current over supply of gas, are not being fully enjoyed by gas consumers. In order to give the direct benefit of cheaper gas to consumers, the FERC proposes a four part program:

- Pipelines will be required to divide the gas they purchase into two blocks. The first block contains low-cost "old gas" to be allocated to existing firm customers. The second block represents the pipeline's higher cost gas which is to be used for incremental sales to present customers as well as for sales to new markets;
- Pipelines are encouraged to negotiate with producers to buy-out future take-or-pay liability, by removal of all provisions in their gas purchaser contracts requiring the purchase of any specific

quantity of gas. The pipeline would be permitted to recover in its rates a portion of these "buy-out" payments;

- Pipelines may transport gas for others under a blanket certificate program, provided there is no discrimination as to eligible shippers; and
- An expedited certification program is offered allowing pipelines to build new facilities associated with their service to new markets, if they are willing to accept all risks inherent in these investments.

One major problem with the proposal is its tendency to raise the rates that consumers pay for gas. This occurs because the proposal will cause a market loss for most pipelines. After a pipeline's customer has purchased his share of the low-cost, Block One gas, the proposal would allow the customer to purchase an increasing amount of gas from other sources, as an alternative to the pipeline supplier's more expensive Block Two gas. These customers can purchase cheaper "spot gas" in the field and have it transported to them by any pipeline that may have access to the customer. If the traditional pipeline supplier loses a portion of its market in this manner, its costs will be spread to the remaining customers, resulting in higher prices for each unit of gas sold.

This phenomenon is amplified by creation of many new risks for pipelines, particularly the risk that their facilities will be under-utilized. Increased risk means an increase in the cost of borrowing money. Likewise, the regulated rate of return permitted pipelines must increase because of the increased risks involved.

The pipeline network has been built primarily with money borrowed through the issuance of bonds. Typically, these financial instruments require maintenance by the pipeline of specified levels of gas supply. If that supply is not maintained, accelerated payment of the indebtedness is mandated. The FERC's proposal seems to ignore this fact, in that it pressures pipelines to give up their traditional role as a gas supplier to customers and become only a transporter of gas between producers and consumers.

As a pipeline's markets shrink, the pipeline must also try to release a corresponding portion of its gas supply, or be faced with liability to producers for its breach of their contracts requiring gas to be purchased. This evolution from a supplier to a transporter of gas will create massive litigation over the cancellation of contracts, as well as the problem of early maturity of the pipeline's debt, causing it to have to refinance at higher rates of interest, which would ultimately be reflected in the price paid by consumers for the pipeline's service.

It is obvious that segregating all old, low priced gas into Block One and other gas into Block Two will render the Block Two gas initially unmarketable. Even with the benefit of averaging the Block One gas, spot gas is selling today in the field at $2.50/MMBtu and it is barely competing with No. 6 oil in many markets. With continuing falling world oil prices, and the inability to average new gas with old, there could be, under the NOPR, large losses of the gas market to No. 6 oil. Since about one-third of the national gas market (6 Tcf) is competitive with No. 6 oil, the block pricing proposal could result in substantially increasing dependence on foreign oil imports at the expense of our national security and balance of payments.

The proposal is also discriminatory. Customers of a pipeline are expected to reduce their purchases of the pipeline's high-cost, Block Two gas and arrange to purchase cheaper gas directly from producers or other field sources. The expertise to locate, contract, dispatch and monitor one's own gas supply will not be present in all pipeline customers. Generally, the major city distribution company customers and perhaps the larger industrial customers may be able to accomplish these tasks. The smaller, rural customers which cannot cope with these new problems will continue to purchase their gas from their traditional pipeline suppliers, but at increased rates for the reasons explained above.

Another discriminatory feature of the proposal involves the entitlement of a customer to the pipeline's low-cost Block One gas, based on historic usage in 1982, 1983, and 1984. Why should a party which became a customer of the pipeline in December, 1984, enjoy an advantage over another which began purchasing gas in January, 1985?

Yet another major flaw in the proposal is the false premise that there will always be an adequate supply of gas at cheap prices. In times of abundance, buyers enjoy the advantage, and are not worried about high prices or short supply. The history of the gas business, however, shows that supply can be reduced by lower prices and lack of new exploration. Traditionally pipelines, acting as middlemen, have smoothed out these cyclical periods of short and long supply thereby giving consumers more stable and reliable service.

A pipeline's gas supply acts a buffer between gas producers and consumers in two ways. First, since the pipeline purchases gas from thousands of wells in many fields, its gas supply, as well as the pipeline's gas storage ability, can be relied upon to meet peak period demands of consumers during extreme cold weather. Secondly, since the pipeline's gas cost has been calculated on a weighted average, or "rolled-in" basis, cyclical swings in the price of gas in the field do not impact consumers directly. It is certainly true, as presently perceived by the FERC, that this averaging technique prevents the direct impact of falling prices from being felt by consumers. But it is likewise true that consumers are protected from the shock of rising prices by this system.

The proposal attempts to remove the buffering effect of the pipeline's gas supply so that consumers may benefit from presently lower prices. Customers are to give up some or all of this right to purchase gas from their traditional pipeline supplier and substitute individual purchases of cheaper gas in the field which will be transported to the customer. This obviously surrenders the supply reliability of the pipeline as well as subjecting the customer to the direct impact of rising prices in a future gas shortage.

Finally, the proposal would hasten the nation's return to the gas shortages experienced in the 1970's. The proposal would exert extreme downward pricing pressure on gas assigned to the Block Two category. The direct or indirect suppression of gas prices by the government leads to shortages. This fact was plainly recognized by Congress in the enactment of the Natural Gas Policy Act in 1978.

In conclusion, the FERC's effort is certainly well intentioned, but does not appear to have been throughly considered in light of the realities of the gas industry. Far ranging public policy should not be based on temporary economic conditions, such as the present over-supply of gas, when experience has taught that these conditions will reverse themselves. This is particularly true where the policy involves untested theory and undue risk of irreversible damage to a segment of the economy vital to the national interest.

It is therefore recommended that the FERC be urged to withdraw this proposal. The problem (that is, the unsatisfied desire of consumers for cheaper gas), can be approached by more conventional regulatory methods not involving the risks outlined in this paper. For example, the FERC could order pipelines to purchase gas for their customers on a least cost basis, whereby their demands would be satisfied by the cheapest gas on the pipeline's system. Similarly, the take-or-pay, transportation and blanket facilities certification aspects of the proposal are capable of being addressed in a far less radical fashion. The FERC has been given many such suggestions by those which have filed comments. The interests of gas consumers, and the nation, require a through reappraisal and abandonment of this proposal.

UNITED STATES OF AMERICA
BEFORE THE
SENATE SUBCOMMITTEE ON ENERGY
REGULATION AND CONSERVATION

STATEMENT OF COASTAL OIL & GAS CORPORATION

On May 30, 1985 the Federal Energy Regulatory Commission (FERC) issued a 195 page Notice of Proposed Rulemaking dealing with the regulation of natural gas pipelines after partial wellhead decontrol of gas prices. This sub-committee held hearings on this matter on July 11, 1985 and gave interested parties the opportunity to submit for the record their views on this FERC proposal. Accordingly, Coastal Oil & Gas Corporation (COGC) respectfully submits this statement.

COGC is a producer of substantial volumes of gas, a large percentage of which is sold to its affiliate, Colorado Interstate Gas Company, an interstate gas pipeline. In 1984, COGC produced 18.3 billion cubic feet of gas from its interest in 558 gas wells, located principally in the western United States. COGC has a vital interest in the outcome of this matter.

The FERC's proposal, called a "Magna Carta" for the natural gas industry by one FERC Commissioner, would involve the most sweeping and fundamental changes in the regulation of gas pipelines since the passage of the Natural Gas Act in 1978. COGC does not question that the proposal is genuinely intended by the FERC to address market distortions caused by past regulatory and legal restraints placed on the gas industry. Unfortunately, the plan appears to have been devised upon a hypothetical view of the operations of gas pipelines and producers. The proposal is therefore highly impractical. Rather than curing the current distortions in the gas market, the proposal would cause an even greater misalignment of the market place, with higher prices for consumers, shortages of gas, and general chaos in the industry.

The principal problem which appears to trouble the FERC is that falling gas prices, caused by the present over supply of gas, are not being fully enjoyed by gas consumers. The FERC therefore has proposed a four part program, as follows:

* Pipelines will be required to divide the gas they purchase into two blocks. The first block contains low-cost "old gas" to be allocated to existing firm customers. The second block represents the pipeline's higher cost gas which is to be used for incremental sales to present customers as well as for sales to new markets;

* Pipelines are encouraged to negotiate with producers to buy-out future take-or-pay liability, by removal of all provisions in their gas purchase contracts requiring the purchase of any specific quantity of gas. The pipeline would be permitted to recover in its rates a portion of these "buy-out" payments;

* Pipelines may transport gas for others under a blanket certificate program, provided there is no discrimination as to eligible shippers and a pipeline's firm service customers would be able to unilaterally cancel up to 25% per year of the volumes they are obligated to purchase; and

* An expedited certification program is offered allowing pipelines to build new facilities associated with their service to new markets, if they are willing to accept all risks inherent in these investments.

While the plan might appear to impact only gas pipelines, gas producers such as COGC will also experience its ill effects. Like other gas producers, COGC's exploration effort is strongly influenced by the anticipated price of natural gas. Regulatory action which suppresses the price of newly found gas results in fewer wells being drilled, and a consequential reduction in gas reserves to serve the public.

The FERC's proposal would have a negative affect on COGC's operations in three principle ways: (a) the block pricing program would reduce the price paid by pipelines for new gas supplies; (b) the partial cancellation of pipeline customer's obligations to purchase gas would cause an offsetting reduction in the volume of gas purchased by pipelines from producers, thereby diminishing producers cash flow; and (c) the extinguishment of take-or-pay or similar contractual provisions would cause severe problems for producers.

1. Block Pricing: The FERC proposes to require pipelines to divide their gas supply costs into two categories. The first pricing block includes older, cheaper gas still under price regulation. One study of the purchased gas costs of twenty-five major pipelines shows that their average block one cost would be $1.46 per MMBtu. This is below current field prices. Block two would contain the costs of all other gas, generally the newer, higher cost supplies. The same study shows an average block two gas cost for the twenty-five pipelines of $3.60 per MMBtu, or a price considerably above market clearing levels.

It is plain that a pipeline could sell all the block one gas it could acquire, but would have substantial difficulty selling its block two gas in competition with alternative fuels or even in gas to gas competition with lower cost suppliers. Therefor, the proposal exerts pressure on pipelines to reduce their block two average gas cost in order to retain their existing markets or offset market loss by new sales. It follows that this downward pricing effect will continue until a pipeline's average block two gas cost is at a market clearing level. Meanwhile, the block one gas remains below market.

The result of block pricing therefore is to indirectly suppress gas prices to the point where the average price of all gas sold to pipelines, both block one and block two, is below market. The supply of gas can only suffer as the result of this regulatory intervention in the gas market place. The proposal, however, seems to ignore this fact.

2. Reduction of Pipeline Markets: Another aspect of the proposal is the reduction of a pipeline's market by its customer's unilateral cancellation of up to 25% per year of their obligations to purchase gas. Even assuming that there was not a downward trending price effect inherent in the proposal, the reduction of a pipeline's market would harm gas producers.

A producer's revenue is not only based on the price of its gas, but is also a function of the volumes sold. Present worth of a gas well's recoverable reserves is a seriously considered factor in the decision to develop new reserves. Since new gas developed under existing contracts is to be consigned to block two, and block two gas is to be sold to pipeline customers to satisfy their remaining demand after they have purchased their full entitlement of cheaper block one gas, any reduction in a pipeline's market is first reflected in its block two, or new gas sales. The prospect of both lower prices for newly developed gas _and_ reduced volumes of new gas purchased by pipelines in response to shrinking markets work as a double disincentive to the development of gas supply.

3. _Take-or-Pay Extinguishment_: The proposal offers an incentive to pipelines to renegotiate certain "problem" gas purchase contracts with producers, to remove all contractual provisions that might require the pipeline to purchase any specific quantity of gas. These provisions include the obligation to take or pay for a specified volume; to take gas ratably from all producers is a common reservoir; or even to take gas to prevent the producer from losing its gas reserves by virtue of drainage from offset wells operated by others. Legitimate reasons exist requiring gas producers to insist that certain minimum volumes of gas be purchased, when that gas is dedicated to long term sales obligations.

First, a producer must honor the terms of its lease. Courts have held that a producer has an obligation to its royalty owner to market gas prudently. A gas sales contract which commits the producer's gas for a period of years, _but_ does not require the purchaser to take any volume may be considered an imprudent marketing practice, subjecting the producer to liability for damages. The lease is also in danger of cancellation if beyond its primary term and if gas is not produced in commercial quantities, i.e., there is insufficient revenue to cover a producer's operating expenses. Further problems are created for producers which hold leases of public minerals. For example, the federal government may compel production from offshore federal leases at rates in excess of those which the pipeline purchaser desires to take. If a producer has not required its pipeline purchaser to accept volumes ordered to be produced by the government, and the pipeline refuses to purchase such gas, the producer is exposed to severe economic penalties or cancellation of its lease.

Additionally, producers have a duty to their shareholders to prevent the loss of their assets. Therefore, gas sales contracts may require that gas be taken to prevent loss by drainage, or on a non-discriminatory basis with other producers in the same field.

Finally, producers are subject to the same economic considerations as other businessmen. Large investments are made in purchasing leases, geological and geophysical analysis, drilling and equipping wells, and making gas ready for market. Gas is then dedicated to a contract for a period of years. The investment of money by any business cannot be justified without the reasonable expectation of return.

Without such assurance, producers must invest their money elsewhere.

The FERC's proposal seems to be unaware of these valid reasons why producers require certain volumes of gas to be purchased. Producers should not be coerced to relinquish such contract provisions. In fact, it is highly doubtful that producers will agree to such contract concessions. Because the extinguishment of such clauses is a necessary and integral part of the proposal, the failure of this aspect casts doubt on the feasibility of the entire plan.

In conclusion, COGC believes that the proposal presents and undue risk of disruption to the gas industry. For producers, the results will be reduced prices, reduced sales of gas, and possibly exposure to liability arising from disgruntled lessors. None of this will have a positive affect on gas supply. If supply is diminished, prices for gas will rise. In sum, the proposal is an untested and radical "cure" which is far more dangerous than the "disease" it is intended to remedy.

UNITED STATES OF AMERICA

BEFORE THE
SENATE SUBCOMMITTEE ON ENERGY
REGULATION AND CONSERVATION

STATEMENT OF WYCON CHEMICAL COMPANY

On July 11, 1985, the above referenced subcommittee held hearings on a Notice of Proposed Rulemaking issued on May 30, 1985, in Docket No. RM85-1-000 dealing with the regulation of natural gas pipelines after partial wellhead decontrol of gas prices. The subcommittee has given interested parties the opportunity to submit comments on the Federal Energy Regulatory Commission's ("FERC") proposed rules for the record. Accordingly, Wycon Chemical Company ("Wycon") respectfully submits its comments.

Wycon, based in Cheyenne, Wyoming, uses natural gas as a feedstock and fuel to produce ammonia and ammonia-based fertilizer, livestock feed supplement, liquid carbon dioxide, and ammonium thiosulfate fertilizer. Wycon began production and marketing of fertilizer and industrial products 20 years ago. From an initial plant costing about $6 million, Wycon has grown so that the total investment in facilities when the current expansion is completed in September will be $84 million. The products made by Wycon are marketed in an eight state area which includes Colorado, Idaho, Kansas, Montana, Nebraska, South Dakota, Utah and Wyoming. Since natural gas is the principal raw material used by Wycon in making its products, the price of natural gas has a dramatic effect on its ability to stay in business.

In 1984, Wycon spent $16.3 million for gas, its transportation and demand charges. It spent $1.5 million on electrical power, $3.7 million on salaries for 114 people and $8.2 million on other costs, including $0.8 million in taxes. Wycon shipped 300,000 tons of chemical products mainly through seven trucking companies based in Cheyenne which hire 42 people to handle Wycon's needs. This provides an additional estimated annual payroll of $2 million.

Wycon has provided a significant portion of the nitrogen fertilizer needs of Wyoming in past years. In 1982 Wycon provided 25% of Wyoming's needs through direct sales and co-producer exchanges. Those sales fell in 1984 though because of Wycon's inability to meet the demand due to Canadian competition of ammonium nitrate.

Until the middle of 1982, Wycon bought all of its gas from Cheyenne Light, Fuel and Power Company ("Cheyenne"). Cheyenne is a local distribution company which serves Cheyenne, Wyoming and its environs. In 1982, Wycon renegotiated its contract with Cheyenne so that Wycon could purchase gas from companies other than Cheyenne and have that gas transported by Cheyenne. Wycon pays Cheyenne a flat monthly transportation fee regardless of the volume of gas which Cheyenne actually transports. Wycon also continued to pay a demand charge to Cheyenne each month which would entitle it to 17,848 Mcf per month of gas in case of emergency. Wycon used the emergency supply in January 1983, but did not use it at all in 1984. As a result of being able to buy gas on the spot market, Wycon reduced its cost of gas from $3.49 per MMBtu in 1982 to $3.32 per MMBtu in 1984. Wycon expects to reduce its price by at least $0.24 in 1985 if the regulations of the FERC continue to allow Wycon to buy gas directly from producers.

Wycon has spent $47 million in the last two years to expand its plant to add new industrial products and make it more efficient based in part on the assumption that it would be able to hold its gas costs down. The expansion has been projected to generate an annual sales revenue of $22 million, to generate additional taxes of $.8 million per year and to result in nineteen new employees with an annual payroll cost of $.5 million. The expansion is expected to be completed by September, 1985. Unfortunately, that is just about the same time that FERC is projecting as the effective date for its proposed regulations. It is unfortunate because the proposed regulations will totally disrupt the market place and Wycon anticipates that it will be adversely affected by the changes.

Wycon's main objections to the proposed rulemaking are: 1) that the proposed rules will cause state agencies to have to review completely their procedures and mechanisms for regulating gas prices, and 1) that the proposed solutions will actually cause such problems for producers that the market will experience lower ultimate production and greatly increased gas prices in the future.

The FERC has control of gas prices only to the point where the gas is sold to the local distribution company. After that point, the states and local authorities assume jurisdiction. Under the proposed regulations, pipelines would be obligated to sell Block One gas to "existing" customers based on their firm purchases from the pipeline in calendar years 1982, 1983 and 1984. Higher cost Block Two gas would be marketed to the customers of pipelines after the Block One gas had been allocated. The FERC's apparent impression is that Block One gas will be generally sufficient to meet the needs of "existing" customers and that Block Two gas will be billed to "new" customers of the pipeline.

Until the middle of 1982, Wycon bought all of its gas from Cheyenne. Cheyenne in turn bought all of its gas from Colorado Interstate Gas Company ("CIG"), an interstate pipeline. Although Wycon is not aware of the actual percentage of Cheyenne's gas supply which will be purchased from CIG's Block One, we have been informed that CIG expects that it can meet sixty percent (60%) of its existing customer's needs with Block One gas. If that percentage applies to Cheyenne, Cheyenne will be paying Block Two prices for 40% of its gas supply. State regulatory authorities will be forced to make sweeping changes to their regulations to continue the block pricing mechanism in effect for Cheyenne's customers or the proposed pricing mechanism will have no different effect than the current rolled-in pricing mechanism, except to the extent that Cheyenne's current price is greater or lesser than the price resulting from the 40/60 split. Cheyenne will not be an "old" customer getting the benefit of all old low price gas and it will not be a "new" customer paying all higher Block Two prices.

Although Wycon is not currently buying any gas from Cheyenne and is paying only a demand charge, Wycon still may be affected if the states have to review their rules. The state jurisdictional agencies may change the current rules for demand charges, for bypassing local distribution companies or for allocating costs in the future.

At least initially, the Block Two gas will be very high priced. To the extent Wycon is forced to buy Block Two gas, it will be hurt today by higher gas prices. But the proposed mechanism has the potential of a "double whammy". The blocking mechanism will cause pipelines to exert tremendous pressure on producers to reduce their contract prices of Block Two gas to market clearing levels. The Block One gas will be substantially below market clearing level and the Block Two price will approach market clearing level so that the total of both blocks is then below market clearing levels.

When prices are held down by regulation, either direct or indirect, the supply of gas is affected. Producers will no longer sell gas from marginal wells and will not drill deep or tight formation wells. Therefore, in a few years the shortage, which is likely to result anyway, will be greatly exaggerated and Wycon will then be required to pay higher prices for any gas it receives regardless of the spot market or billing mechanism in effect at that time.

In conclusion, Wycon opposes the regulations as proposed by the FERC in its May 30, 1985 notice because of the unnecessary disruptions it will cause to the gas industry. Pursuant to current FERC regulations, Wycon has been able to gradually reduce its gas costs in a way that was satisfactory to the state regulatory agency and the local distribution company. Although the current rules are not perfect, they are more desirable than the drastic measures proposed by the FERC which raise a substantial risk of causing the price of Wycon's basic raw material, natural gas, to become so great that it threatens the economic viability of Wycon.

STATEMENT OF
ROSEMARY T. McFADDEN
PRESIDENT, NEW YORK MERCANTILE EXCHANGE
BEFORE THE
SUBCOMMITTEE ON ENERGY REGULATION AND CONSERVATION
UNITED STATES SENATE

I appreciate the opportunity to submit comments to you concerning the current status of the natural gas markets, and the outlook for a futures market in natural gas. The New York Mercantile Exchange ("Exchange") is a federally regulated futures exchange that has been designated as a "contract market" for the trading of futures in crude oil, heating oil, leaded and unleaded gasoline, platinum, palladium and potatoes. On March 1, 1984, the Exchange filed with the Commodity Futures Trading Commission ("CFTC") an application for designation as a contract market in natural gas futures.

The Exchange initiated efforts to develop a natural gas futures market in early 1983, as competitive pressures emerged within the natural gas industry. Recognizing that there are still a number of regulatory and contractual issues to be resolved before a successful futures contract may be introduced for trading, the Exchange has been closely following legislative and regulatory discussions and potential rule changes that may directly impact natural gas pricing and distribution. One area of particular concern to the Exchange is the regulation of and access to transportation. The Notice of Proposed Rulemaking recently issued by the Federal Energy Regulatory Commission is viewed as a positive step in addressing one of the principle obstacles to competitive markets in natural gas, the absence of an efficient and easily accessible transportation network. The extent to which FERC regulatory action provides for more flexible transportation arrangements is a key determinant in the evolution of a competitive market for natural gas and of the development of a viable futures market to serve the needs of that market.

In order to understand the role a futures market may play in the natural gas market, the basic futures concept must be reviewed. Futures contracts are standard agreements to buy and receive - or to sell and deliver - a stated quality and quantity of the product specified at a definite future date. The contract terms are standardized; the only condition that is set at the time of trade is price. All trading is done by open outcry, in a single location on the floor of an exchange, which is regulated by the Commodity Futures Trading Commission.

A futures market represents the purest form of an open and competitive pricing system, where price opinions are brought together in a central location for trading. Since futures positions are based on cash market commitments, the transaction price of the futures contract represents the equilibrium price of the commodity at any given moment, and a valid indication of all supply and demand fundamentals.

Typically, a futures market develops in response to economic forces in the underlying commodity market. It is not invented or imposed on a commodity, rather, it evolves out of the need for the performance of functions that the existing market system does not address effectively.

Competitive market forces have already spurred the development of a spot market in natural gas. Current estimates indicate that on an annualized basis 2 to 2.5 trillion cubic feet (Tcf) of natural gas are moving under short-term flexible pricing schemes. This volume is expected to grow as the industry becomes more familiar with the mechanics of spot trading. As the spot market matures, prices will fluctuate more freely, and market participants will be exposed to a greater degree of price risk. The introduction of a natural gas futures market will assist the industry to operate more efficiently and effectively in a market that will be increasingly characterized by uncertain prices.

A well developed futures market can be used as a price discovery tool, promoting increased competition in the natural gas markets. In the cash market, prices are set by many individual transactions which are difficult to measure on a daily basis. The futures market will provide a highly visible marketplace for trading natural gas.

Futures prices are widely disseminated and are readily available to everyone regardless of whether they are involved in futures market trading. They are published in major daily newspapers, as well as transmitted globally by telecommunications systems. On any given day a potential buyer or seller of natural gas will be able to refer to the Wall Street Journal or New York Times to ascertain the previous day's closing prices for futures contracts of natural gas, as well as the range of prices for contracts traded on that day. In addition to listing futures prices for all months traded, a volume estimate is provided to lend support to pricing information generated by the Exchange. This may be particularly beneficial to the gas industry in a decontrolled environment, by providing buyers and sellers a reliable and readily available price indicator for natural gas. Prices are available for futures contracts traded in the current month, and for each consecutive month for eighteen months forward. The oil industry has found this price-discovery mechanism most useful, and many have, in fact, cited futures prices as a price basis in contracts and for fixing cash market transactions.

The second major function of a commodity futures market is to provide a mechanism for risk management. This is accomplished through hedging: the simultaneous initiation of a futures market position to offset the price risk of a spot market position. Hedging is a calculated strategy in which price risk exposure is counterbalanced in the futures market. It allows commercial participants to transfer their future price risk to speculative investors or other commerical participants with differing risk management needs. Hedgers provide the backbone of commodity futures trading and are, in fact, the reason for its existence. For natural gas futures, all industry segments may want to hedge price risk, including interstate and intrastate pipelines, producers, resellers, distributors, and end-users. By locking-in prices at a known level, hedgers may limit, or even eliminate, the losses which may result from adverse price movements in the cash market.

It is important to note that hedging is, in essence, a financial transaction: the hedger having no intention of making or taking delivery in the futures market. Less than 2% of all futures contracts traded on the Exchange actually result in physical delivery, yet, delivery is an important aspect of futures trading. Delivery insures price convergence between cash market prices and futures market prices, and thereby preserves the integrity of the contract. Consequently, a workable delivery system, with an efficient transportation network, is necessary to the success of any futures contract. That mechanism must be readily available to all market participants for the completion of deliveries in an efficient and timely manner.

Deliveries are made on the Exchange after trading has terminated in each contract month, and the Exchange has matched all buyers and sellers who have remained in the market for deliveries. The buyers and sellers in a futures market are represented by Clearing Members (i.e. Merrill Lynch, Paine Webber, etc.) acting as agents for their customers. As currently structured, the natural gas contract provides for delivery at Bammel Field and Katy, Texas. The seller nominates the delivery location and pipeline interconnection point where the transfer of title will occur. The buyer is then required to arrange transportation to pick up the product at the point.

Since futures deliveries are short-term transactions (30-days), transportation must be arranged in a timely manner. Extensive research has been done in the Texas intrastate market with regard to available pipeline capacity and the willingness of the pipelines to transport gas for others. The Exchange has found evidence of a growing spot market for natural gas in Texas, where transportation services to third parties are generally competitive, and an increasing share of pipeline revenues is derived from such third party transport business. Further, transportation arrangements may be completed within a relatively short time frame, since intrastate pipeline companies are not required to seek prior approval from the Texas Railroad Commission for the initiation of service. Therefore, futures deliveries exclusively within the borders of Texas may operate efficiently.

For interstate participants to avail themselves of the potential uses of the futures market, however, greater flexibility is necessary with respect to the regulatory requirements subject to FERC jurisdiction. Individual NGA transportation certificates are ill-suited for the delivery requirements of the gas futures contract, as well as for pure spot transactions. The new transportation rules proposed by the FERC are expected to provide much needed assistance to buyers and sellers of natural gas who must arrange timely transport agreements. The FERC should be supported in its efforts to develop competitive and efficient transportation services within the natural gas industry.

The momentum of the market is spurring changes in traditional business practices. After decades of controls, a significant portion of natural gas supplies has become deregulated. Natural gas has become a commodity, and as is the case with other commodities, the supply and demand for the product becomes driven by price. A growing spot market has evolved in natural gas and with the spot market, the demand for transportation services has increased. Innovative pipeline companies have and will continue to recognize new business opportunities in transportation and will adapt business strategies to the changing demands of the marketplace. The industry has also witnessed the advent of gas-to-gas competition. Companies are not only competing for market share with alternative fuels, but also with other gas companies. In this aggressive marketing environment, companies will seek to differentiate themselves on the basis of cost and service. To survive they will have to become innovative competitors. The introduction of a natural gas futures market may assist the industry to operate more efficiently in the emerging competitive marketplace.

DEPARTMENT OF ENERGY
BEFORE THE
Federal Energy Regulatory Commission
WASHINGTON, D. C.

1985 JUL 1

Regulation of Natural Gas Pipelines) Docket No. RM85-1-000
After Partial Wellhead Decontrol)

EXECUTIVE SUMMARY OF COMMENTS OF THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERICA

The Notice of Proposed Rulemaking (NOPR), issued in this proceeding on May 30, 1985, is the most significant regulatory proposal this Commission has ever made relating to interstate natural gas pipelines. It is a bold, even radical, attempt by the Commission to restructure the interstate natural gas pipeline industry and yet at the same time "ensure that...natural gas markets are viably and sufficiently competitive so that consumers are provided gas at the lowest reasonable rates consistent with reliable long-term service." (NOPR at 3) This stated goal is consistent with the Natural Gas Act and the interstate gas pipeline industry supports it. To achieve this end, it is essential, among other things, that all sectors of the natural gas industry -- producers, pipelines, distributors, brokers, etc. -- be placed in comparably competitive positions. A careful balance is essential if there is to be fair competition and equitable distribution of the increased market risks. Consistent with this aim, incentives need to be provided all segments of the industry, especially with regard to non-market responsive contracts and take-or-pay if, in fact, the fabled "playing field" is to be truly level for competition.

The following is a summary of INGAA's basic position and suggested recommendations.

A. Billing Procedures for Purchased Gas -

The proposal establishes a three block billing system for purchased gas. This block pricing approach does away with forty years of rolled-in pricing on the theory that more responsive market signals need to be conveyed from the wellhead to the consumer.

Most pipelines' Block 2 gas, which accounts for about 50 percent of gas sold in the interstate market, currently has an average price of $4.00 per MMBtu.1/ When compared with the current price of $2.50 per MMBtu for spot market gas, it is apparent that most Block 2 gas is not marketable. Given this fact, pipelines with high cost Block 2 gas are faced in the NOPR with the prospect of not being able to compete for new markets and with the loss of existing markets. Additionally, intrastate pipelines and local distribution companies (LDC) typically will be able to continue to use rolled-in pricing with the LDC's rolling in a cushion of Block 1 gas from their pipeline supplier.

INGAA recommends that the Commission create an additional block or sub-block that would include market responsive gas and new gas. This would assist the pipelines in competing on a more nearly level playing field.

B. Take-or-Pay -

If some viable means of relief is not provided to allow Block 2 gas to compete, the already considerable take-or-pay exposure confronting

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1/ Source: January through May, 1985 data from Table 22, Natural Gas Monthly, April 1985, published June 1985 [DOE/EIA-0130 (85/04)]. Energy Information Administration Publication.

pipelines will be exacerbated. This part of the NOPR is critically intertwined with the block pricing mechanism and both must work if either is to work. However, this buy-out/"safe harbor" will not work. Producers will not have an adequate incentive to grant take-or-pay relief and the pipelines will risk being unable to recover all of their buy-out payments and carrying costs, or earn a return on the buy-out investment. It follows therefore, that the pipelines will have difficulty in financing the huge amounts of money that the proposed buy-outs will require.

Current take-or-pay exposure of interstate pipelines is considerable -- approximately $5 billion in 1984 for companies representing about two-thirds of the interstate market. Additional exposure of $3 billion is estimated for 1985. The post-1985 exposure would be even greater under the NOPR. Using 1985 as a benchmark, the minimum "1986-87 unrecoupable obligation" for take-or-pay will be approximately $6 billion with actual buy-out payments likely to exceed the two years of take-or-pay exposure. The annual carrying costs alone to the pipelines will be in the billions because, for every billion dollars of buy-out, the carrying costs are estimated at roughly $400 million. This would extend over a five year period. In light of these figures, the proposed buy-out/"safe harbor" cannot be looked upon as a panacea to the take-or-pay problem.

INGAA recommends that the final rule provide that producer access to the self-implementing transportation program be conditioned on a grant of take-or-pay relief. Another alternative would be for the FERC to require producers to grant take-or-pay relief in return for release of gas by pipelines with provision for expedited abandonment. These alternatives should be appealing to producers enthusiastic for open transportation as reflected by statements made by their representatives at the first NOI Public Conference that with open transportation, take-or-pay would "take care of itself."2/

C. Self-Implementing Transportation Program -

The NOPR's self-implementing transportation program would be conditioned so that a participating pipeline would have to provide open and "nondiscriminatory" transportation. This raises a question as to the meaning of "nondiscriminatory" in the context of the NGA standard of "undue discrimination" and the standards by which it is to be assessed. Furthermore, a pipeline would apparently only have one opportunity to get into the program and it is not clear whether it could get out. This lack of flexibility does not seem to be consonant with the Commission's intent, and it certainly will increase the likelihood of operational problems for participants.

In addition, a participating pipeline's firm sales customer can, at its discretion, reduce its contract demand at the rate of 25% per year for four years, which raises questions of the need for payment of demand charges for reserved capacity, relinquishment of Block 1 gas allocations when contract demand is reduced, the legality of this sort of unilateral *de facto* abandonment, operational planning, allocation of costs, and the enhanced possibility of customers converting to alternate fuels.

Self-implementing transportation would be on a firm basis. However, while it is firm as to capacity, it is not firm as to any individual transportation customer. This is in contrast to traditional

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2/ Statement of Ms. Patricia Eldridge on behalf of Oklahoma Independent Petroleum Association, Public Conference, Notice of Inquiry, Docket RM85-1-000 (Phase I), February 20, 1985 (Tr at 195).

firm sales service. To the extent firm capacity is available on the peak or average day basis, it is unclear how that capacity, which only occurs from time to time, can be secured as "firm". INGAA recommends that pipelines be given the flexibility to perform self-implementing transportation on either an interruptible or traditionally firm basis. A new class of "firm" transportation should not be established.

D. Optional Expedited Certificates -

The Commission intends that the optional expedited certificate procedure be used as part of a total program to foster competition and to break down barriers to entry. INGAA recommends that the Commission allow the parties to bargain for a rate design, including demand or reservation charges, which balances their interests and is economically feasible under specific circumstances. Also, INGAA recommends specific modifications to the proposed optional certificate program to enable pipelines to compete with other possible entrants.

E. Legal Concerns -

The following is a list of some of the more significant legal questions. They relate to the Commission's authority to:

(1) do away with rolled in pricing;

(2) deregulate pipeline Block 2 gas after four years;

(3) allow *de facto* unilateral abandonment of firm gas sales contracts;

(4) order mandatory carriage by indirect means;

(5) allocate Block 1 gas to existing firm sales customers; and

(6) impose rates that may be confiscatory and anti-competitive.

These and other legal questions are addressed in INGAA's comments.

F. Conclusion

Notwithstanding the tremendous effort in issuing so comprehensive a proposal in the short span of time since the NOI, there is a real need for the Commission to make certain modifications and clarifications if the rule is going to provide the basic services and competitive market environment that are intended. INGAA's comments are meant to suggest the adjustments and modifications that need to be made to the broad framework of the rule before its implementation. Toward this end, we believe that our proposals will further, rather than detract from, the Commission's stated goal. Due to the magnitude of the NOPR, INGAA recommends that prior to the issuance of any final rule herein, the Commission convene a technical conference, or series of conferences, to develop the details of implementation.

UNITED STATES OF AMERICA

FEDERAL ENERGY REGULATORY COMMISSION

REGULATION OF NATURAL §
GAS PIPELINES AFTER § DOCKET NO. RM85-1-000
PARTIAL WELLHEAD DECONTROL § (PARTS A - D)

EXECUTIVE SUMMARY OF COMMENTS OF ARKLA, INC. ON NOTICE OF PROPOSED RULEMAKING

July 15, 1985

EXECUTIVE SUMMARY OF COMMENTS OF ARKLA, INC. ON NOTICE OF PROPOSED RULEMAKING IN DOCKET NO. RM85-1-000

Arkla, Inc. ("Arkla")[1] strongly supports the thrust of the regulatory changes proposed by the Commission. In this Notice, the Commission has recognized that in many instances allowing market forces to operate in this industry will accomplish a more efficient allocation of goods and services than continued governmental regulation. The Commission has carefully crafted a set of proposed rules which are intended to achieve that end.

However, Arkla emphasizes that none of the proposed rule changes will succeed unless the massively market-distorting effects of the protectionist state ratable take rules also are addressed by the Commission's rules. Absent a reduction of the market restraints created by these rules, pipelines, producers and end-users still will not be free of the most important artificial prop currently supporting above market-clearing prices. (See discussion at Part B below). Moreover, the Commission must carefully assess the full impact of certain other of its proposed actions; the unintended effect will be to shift an undue portion of fixed costs to certain customer groups (particularly, residential customers). (See discussion at Parts A and C below).

Part A - As ought to occur in a rational market economy, the proposed blanket transportation program should lead to a nationwide transportation network which allows all participants in the industry the opportunity to access all supplies, transportation routes and markets. However, in adopting rules on this subject, the Commission should make some modifications in order to avoid unduly burdening certain customers with costs properly allocable to others. In this regard, Arkla recommends that:

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[1] For a more detailed description of Arkla's operations, see Appendix A attached hereto.

* Sales customers (including direct sales customers) who exercise their contract demand reduction rights should be required to continue to bear their historical portion of the system's fixed costs during the remaining term of their individual service agreements.[2] If they are not so required, the "captive" customers served by that system--those which do not have reasonable access to a competing transportation system--will be unduly burdened.

Arkla also recommends amending the proposals so as to:

* Provide a pipeline's customers with even greater flexibility in exercising their contract demand reduction rights, further extend such rights to include customers of intrastate pipelines, and broaden the scope of the self-implementing portion of the Commission's transportation program to include arrangements in which the customer pays a capacity reservation charge.

* In recognition of the increased market risks faced by pipelines in the new environment, and in order to avoid shifting costs unduly, permit pipelines a greater upside potential by raising the proposed rate-band ceiling with respect to shippers to whom the pipeline previously has given a discount.

* Establish priorities for *capacity*-related curtailments in the following order: (i) firm sales and reserved capacity shippers; (ii) "firm" shippers; and (iii) interruptible sales and shippers, with available capacity within the last two priority categories being rationed by the free market.

* Permit pipelines to file tariffs which require as a precondition of access to transportation the satisfaction of certain operational criteria necessary to ensure the safe and economically efficient operation of the pipeline system (*e.g.*, quantity and quality of gas, minimum notice, minimum duration, acceptable delivery and redelivery points).

* Permit the recognition of each pipeline's historical form of rate design (whether Mcf-mile, zonal or system-wide) in the establishment of its *initial* transportation rates rather than mandating a generic rule.

Part B - The Commission is absolutely correct in its perception that the key to the success of its interrelated proposals is the development of a mechanism which enables producers, pipelines and end-users to resolve the market disorders which currently exist in wellhead gas purchase contracts.

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[2] All such payments, however, would serve as a capacity reservation charge and entitle the customer to "cadillac" transportation service of an equivalent volume.

However, the Commission's goals will not be achieved--even if the Commission's proposals work perfectly to resolve the take-or-pay dilemma--unless the Commission's rules also remove the massively market-distorting effects of the protectionist state ratable take rules. As one of the largest onshore wellhead purchasers from non-affiliates in the industry,[3/] Arkla stresses that, absent such a step, distortions will remain in the wellhead market because the state ratability rules will continue to prevent producers and pipelines from maximizing production in exchange for more market-responsive prices. Under those state rules, recalcitrants who continue to hold out for above-market clearing prices will still be granted a "ratable" share of the market.

For the Commission's program to succeed, it must, uniformly, enable those producers and pipelines who agree to respond to the market the opportunity for increased takes, and deny similar opportunities to producers and pipelines who attempt to continue to maintain above-market prices. In short, the message which must be sent to the wellhead is the essence of free market economics: greater sales for those whose prices are market responsive. Arkla, therefore, urges the Commission to:

* Establish a new intermediate gas category between the proposed "billing" categories of Block 1 and Block 2 which will consist of all gas purchased pursuant to contracts with market-responsive pricing and take-or-pay provisions;

* Mandate that pipelines sequence takes of gas based on these categories --with the lower-priced blocks taken in preference to the higher-priced blocks; and

* Remove from the scope of the non-discriminatory access to transportation provisions on a given pipeline's system, producers who have not agreed with that pipeline to market-responsive terms and conditions for their gas.

[3/] Unlike most other major pipelines, Arkla acquires virtually all of its supplies directly from onshore producers at the wellhead. Thus, Arkla is especially sensitive to, and affected by, this portion of the Commission's proposal.

Part C - Arkla fully agrees with the Commission's proposal to increase the role of competitive forces in the industry by reducing the regulatory constraints which presently frustrate the ability of new suppliers to serve new markets. To avoid unduly burdening certain customers with costs properly allocable to others, however, some modifications should be made. Thus, Arkla urges the Commission to modify its proposal, as follows:

* Allow the parties to an "optional" transaction to set their rates by contract. The Commission's program ensures that no pipeline will be able to exert monopoly power over any customer with respect to services provided under the optional certificate. The freedom to allocate the economic risks of these transactions by arm's-length bargaining will result in a more efficient allocation of the goods and services and instill accountability and economic discipline on consumers as well as pipelines.

Absent such a proposal, regardless of how many barriers the Commission attempts to erect, the increased risks to the pipeline created by such projects will be borne by its "captive" transportation customers--if nowhere else, at least in the form of higher debt and equity costs. In addition, the Commission should:

* Broaden the coverage of the optional certificate to allow expansion of or incremental additions to existing facilities.

* Assure pipelines that acceptance of an optional certificate will not result in assigning part of the cost of existing facilities to a permanently imputed volume representing optional certificate services.

Part D - Arkla fully endorses the Commission's gas categorization proposal and, indeed, based on the concerns expressed at Part B above, recommends that the Commission go farther and use the proposed pricing blocks to establish the framework for each pipeline's purchasing practices. The following modifications also will aid transition to the new billing mechanism:

* Make the new procedures effective simultaneously on all pipelines.

* Allow the presumption of just and reasonable pricing for free-market gas to be phased-in in conjunction with the corresponding opportunity afforded firm sales customers to reduce contract demand.

EXECUTIVE SUMMARY OF THE COMMENTS OF THE AMERICAN PUBLIC GAS ASSOCIATION

The American Public Gas Association ("APGA") is concerned that the Commission's Notice of Proposed Rulemaking ("NOPR"), if enacted without significant changes, 1/ will have a serious adverse economic impact on the nation's over 900 publicly-owned gas systems (as well as the scores of similarly situated investor-owned systems), impairing their ability to render adequate, reliable service to their customers at reasonable rates. APGA accordingly proposes the following changes to the Commission's NOPR:

1. NONDISCRIMINATORY TRANSPORTATION PROPOSAL.

A. Effect On Curtailment Plans. The Commission should amend its proposed rules to make clear that existing distributor-customers of a pipeline have first claim on both capacity and supply during curtailments resulting from a shortage of either, to the extent that their requirements are reflected in existing pipeline curtailment plans. Such a rule will avoid interruption of service to high priority human needs consumers. The Commission should also give pipelines authority to appropriate transportation gas destined for low priority users during supply emergencies (with provision for compensation) to ensure uninterrupted service to high priority, human needs consumers.

B. The Definition Of "Firm" Transportation. The "firm" self-implementing transportation envisioned in the NOPR will be virtually useless to distributors with largely high priority loads because pipelines can interrupt service if they have insufficient capacity. Pipelines should be required to render (i) truly firm nondiscriminatory transportation service

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1/ APGA disagrees with the Commission's initial premise that "nondiscriminatory transportation" is the cure for the problems besetting the natural gas industry, but, for purposes of its comments herein, has not taken issue with this proposition.

to the extent that they have available capacity after accounting for the needs of their firm sales customers, and (ii) nondiscriminatory interruptible service if they have insufficient available capacity.

C. Changes In Distributor-Pipeline Contracts. To ensure that distributors truly have access to nondiscriminatory transportation, the Commission should expressly abrogate all "sole supplier" or "full requirements" provisions in pipeline tariffs and service agreements. It should also amend the "contract demand" ("CD") reduction provision of its proposed regulations to permit small, low load factor distributors (*i.e.*, those with CDs of 20,000 Dth/D or less) to transport gas without risking the loss of a corresponding portion of their CD's. Because of their small size and highly seasonal loads, these customers will be unable to utilize nondiscriminatory self-implementing transportation if it means losing the CD necessary to serve residential and commercial consumers on peak days. The Commission should also adopt specific regulations ensuring that (i) fixed costs will not shift to a pipeline's remaining sales customers as a result of CD reductions; (ii) CD reductions are limited in size and spread out over time to give pipelines an opportunity to adjust their purchasing policies accordingly; and (iii) large distributor-customers which reduce their respective CD's receive corresponding decreases in their supply curtailment entitlements and Block One gas entitlements.

D. Transportation Rate Concerns. APGA supports volumetric pipeline rates for both transportation *and* sales, and thus supports the Commission's volumetric transportation rate proposal. APGA believes, however, that the Commission's proposed regulations must be expanded to (i) prohibit non-cost based "value of service" transportation rates as inconsistent with the Natural Gas Act's "just and reasonable" standard; (ii) define such terms as "incremental cost," "fully allocated cost," and "representative volumes"; (iii) prohibit selective pipeline discounting of transportation rates as unduly discriminatory under the Natural Gas Act; and (iv) prevent subsidization by existing distributor-customers of facilities built to serve incremental transportation load.

E. Potential For Distributor Bypass. APGA believes the Commission has failed to confront the fact that its nondiscriminatory transportation proposal will encourage industrial users to bypass physically the distributors that presently serve them. These matters are most appropriately left for state and local governments to resolve; hence, the Commission should refuse to authorize construction of bypass facilities in the absence of the affected distributor's consent or the approval of the local regulatory body having jurisdiction.

2. TAKE-OR-PAY BUY-OUT PROPOSAL.

APGA has serious reservations about the Commission's proposal to permit pipelines to amortize lump-sum payments made to discharge take-or-pay obligations in their rates, especially in the absence of a pipeline's showing that it incurred these payments prudently. The Commission's proposal as presently structured is contrary to its philosophy of permitting competition to supersede regulation where competitive forces exist. APGA believes that Commission actions such as prohibiting inclusion in pipeline rates of take-or-pay prepayments made under contracts with onerous take-or-pay clauses and finding producer acceptance of unrecoupable take-or-pay prepayments violative of NGPA Title I would be more constructive measures. If the Commission decides to go forward with its lump-sum amortization proposal, however, it should amend its proposed regulations to (i) tighten the definitions of "qualifying contract," "minimum payment or purchase obligation," and "1986-1987 unrecoupable obligation"; (ii) require pipelines to file information with their lump-sum amortization filings sufficient to permit third party scrutiny; (iii) adopt a lump-sum recoupment payment percentage of 7.5% for all qualifying contracts; and (iv) allocate all pipeline costs associated with these payments to incremental transportation customers.

3. BLOCK PRICING PROPOSAL.

APGA generally opposes continued rolled-in pricing because it masks the true cost of gas; hence, it generally supports the Commission's block pricing proposal. APGA believes that the Commission should amend its proposed regulations to (i) require pipelines to place all imported gas costs in Block Two; (ii) require all pipelines to use the Block One entitlements methodology set out in the regulations, and (iii) require pipelines to recover their Block Three gas costs volumetrically by alloting an equal portion of these costs to each unit of projected sales. Moreover, APGA disagrees strongly with the Commission's proposal to presume that Block Two gas prices of nondiscriminatory pipeline transporters are just and reasonable after a transition period. The Commission's proposal constitutes an abdication of its NGA responsibility to protect consumers. Moreover, it is based on an erroneous premise, *i.e.*, that all distributors will be able equally to use nondiscriminatory self-implementing transportation. To the contrary, small, low load factor distributors will be largely unable to do so; thus, the Commission must continue to review pipelines' sales rates to ensure that they are indeed just and reasonable.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol	)))	Docket No. RM85-1-000 (Part A-D)

EXECUTIVE SUMMARY OF COMMENTS OF NATURAL GAS PIPELINE COMPANY OF AMERICA ON NOTICE OF PROPOSED RULEMAKING

Natural Gas Pipeline Company of America (Natural) is concurrently submitting its comments on the Commission's Notice of Proposed Rulemaking (NOPR) issued May 30, 1985 in the captioned docket. The Addendum at the end of those comments discusses the substantial legal questions concerning the Commission's authority to promulgate the regulations proposed. Major points in Natural's comments on the NOPR itself are summarized here.

A. Block Pricing Structure

Natural favors the continuation of rolled-in pricing. This method is equitable, easily administered and consistent with the Natural Ga Act requirement to avoid undue discrimination. Supplies have been acquired and myriad of contractual obligations have been undertaken and facilities constructed based on the long-standing practice of rolled-in pricing.

An alternative to the Commission's proposal would be to include all gas purchased under existing contracts in Block 1. Only new supply commitments would be in Block 2. This approach would achieve the Commission's intended result of creating a "level playing field." At the same time it would avoid the severe retroactive impact of a departure from rolled-in pricing on contract and certificate obligations entered into prior to the effective date of the new rule. All pipelines would start afresh on the "level playing field" espoused by the NOPR, and proper market signals would be transmitted for such new supplies.

If the Commission determines, however, that some form of block pricing along the lines proposed in the NOPR is necessary, Natural recommends that block pricing be structured as follows:

Block 1: Same as NOPR

Block 2a: All gas under new contracts and any existing or renegotiated "market sensitive" contracts

Block 2b: All other gas

Block 3: Same as NOPR Block 3

Even with this revision, there would still be fundamental changes in the gas industry of highly questionable legality. However, this proposed structure will more effectively realize the objectives of the NOPR. There is no evidence the rate structure proposed in NOPR would result in a "level playing field" and Natural believes it would create many inequities. The proposed alternative will better enable pipelines to compete on a more equal footing with new selling entrants. It will give producers an incentive to renegotiate contracts which are not "market sensitive," so as to move their gas into

Block 2a. It will also provide a more accurate "market signal" at the burner tip. Therefore, this revision in block pricing will enhance the Commission's goals of a "level playing field" and foster a greater role for market forces in the gas industry.

B. Nomination By Vintage

Many existing pipeline-producer gas contracts cover gas of more than one vintage and cannot contractually be segregated into blocks. Therefore, in order for the NOPR to operate as intended, it is imperative that the Commission order delivery of all available Block 1 gas first. In addition, the Commission should direct pipelines to adopt a "least cost" purchasing strategy as to other blocks. These steps will ensure that consumers obtain the complete and total benefits of Block 1 and Block 2a gas and will also provide pipelines with at least some tools which will be required to implement the NOPR at the producer level. Alternatively, all gas purchased under contracts with an average price at or below the NGPA §109 could be included in Block 1.

C. Contract Reduction

In light of the unilateral nature of the contract reduction right, customers exercising this right should first be required to convert to firm transportation service on the existing pipeline system and should be required to pay a reservation charge for the duration of their service agreement. These customers should also be assigned the of take-or-pay costs generated by their contract reductions. These steps are an essential ingredient necessary to avoid shifting of costs among remaining customers and to recognize the costs imposed by such customers on the pipeline system, based on the contract demand they would be electing to reduce.

In addition, contract reduction should be allowed only once annually and on at least six month's prior notice to allow the pipeline some opportunity to adjust its operations, marketing and gas supply. Customers electing to reduce contracts but who have no need or intention of converting to firm transportation service should be required to pay an amount sufficient to avoid any cost shifting to remaining customers for the duration of their service agreement.

D. Take-Or-Pay

The NOPR if enacted as proposed could result in very large increases in take-or-pay liability. The proposed buy-out mechanism is not an effective way of dealing with this problem. Natural urges the Commission to accept as prudent negotiated pipeline-producer arrangements to deal with this problem. In addition, if the interstate system is to be opened up to greater access and competition through exercise of the Commission's conditioning powers, producers desiring to avail themselves of this open transportation system should also be subjected to a condition requiring waiver of take-or-pay provisions in their gas contracts with pipelines who hold themselves out as transporters for others.

E. Transportation

Natural does not object to open access to its system. However, it should retain its discretion to restrict availability on the basis of considerations of efficient operation of the system and also its control over the ratemaking process. Natural also favors continuation of the historical "bright line" distinction between firm transportation with a demand charge and interruptible service under volumetric rates. Natural is not opposed to the fixing of "representative levels" so long as there is some degree of flexibility which permits future changes of these levels.

F. Optional Certificate

Natural favors the optional certificate procedure. However, the Commission should recognize the possibility of "by pass" and should state that one of the intended effects of this procedure is to enable pipelines to compete in their traditional markets on an equal footing. To that end, construction or increases in size of sales taps under NGPA §311 should be subject to the same type of notice and protest mechanism as contemplated by the optional certificate procedure.

In addition, pipelines should be permitted to negotiate the terms and conditions of their rates with the company requesting service. The optional procedure will be of more value if buyer and seller can allocate risk by contract in the same manner as exists in a free market commercial setting.

Finally, representative levels related to such services should not be fixed forever. While costs of facilities constructed specifically to serve a particular customer are properly allocated to that customer, representative levels should be permitted to change from time to time as services increase or decrease as contractual arrangements expire, or as new services are added.

G. Conclusion

The NOPR, as drafted, represents a major restructuring of the natural gas pipeline industry. Natural is prepared to move forward in this new regulatory environment but believes that the modification of the proposed regulations set forth herein would better achieve the major goals the Commission has listed in the NOPR. Natural urges the Commission to carefully consider the proposals contained in Natural's comments.